Masters Thesis

Application of "Casing and Liner while Drilling" Technology for OMV Pakistan

In
Cooperation
with
OMV Pakistan GmbH

Presented to the Faculty of Drilling and Completions Engineering

in Partial Fulfillment

of the Requirements

for the Degree of

Master of Science

The University of Leoben, Austria

September, 2016

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Declaration

I hereby declare that most of the work while implementing this project is carried out by myself and has not been submitted previously for any higher degree except where due reference(s) has/have been made in the text.

Date

Signature

Acknowledgement

First of all, thanks to ALLAH Almighty for his blessings.

I would like to pay gratitude to my advisor Mr. Abbas Roohi for his guidance, help, suggestions and moral support during this study.

I would also like to thank Mr. Karl Berghofer, Manager Well Engineering OMV Pakistan, all the drilling team and other concerned departments for giving me a chance to work with real field data. Their help and suggestions on applying the theoretical concepts to real time data have helped a-lot to improve my practical knowledge. They have always been kind and showed their deep interest in the project and led me complete this project in a professional manner.

I am also thankful to Steve Rosenberg, Head service quality assurance, Weatherford and Moji Karimi for guiding me and generously replying to my long emails. Both these men are champions of casing drilling and are authors of lot of papers on Casing drilling.

In addition, I would also like to thank my friends, colleagues, department faculty and staff for making my time at University of Leoben a wonderful experience.

Finally I would like to thank my family for their help and support during my whole study period.

Abstract

Present day challenges faced by oil and gas industry remind us to find ways which are more reliable, economical and robust. Improved methods for drilling and completing the wells are required. Mechanical instability of the wells compels us to think of better drilling methods. Casing while drilling (CwD) is one of the techniques which make us drill more reliably and more confidently.

The approach of using CwD is that casing is used in place of a drill string. It means the well is drilled and cased simultaneously. When a well is drilled to total depth (TD), casing is cemented in place. Unconsolidated formations having swelling and caving-in problems are best suited for this. Loss circulation zones are also potential candidates.

This method of drilling has got several advantages over conventional drilling methods. It reduces the hazards related to excessive pipe handling. Mud fluid loss is reduced and higher equivalent circulating density (ECD) can be obtained with the same mud weight. This is due to the “plastering” effect of casing drilling on borehole wall. Thus, Casing with drilling improves overall drilling efficiency by reducing non-productive time (NPT) [1].

CwD has been in use for quite some time and its purpose is now well understood. This technology can be used with present day rigs with little or no modifications. Depending on the utilization, retrievable and non-retrievable bottom hole assembly (BHA) and bit systems can be used.

In this thesis, the application of Casing while drilling (CwD) & Liner while drilling (LwD) along with its technical feasibility in the Miano field of OMV Pakistan is discussed. This thesis is done to find the best possible match between the requirements of the company, availability of different equipment and service providers present in the market. Finally, a new wellbore “Miano NN” is designed and cost analysis is done to prove its applicability in company’s current operations.

Kurzfassung

Die heutigen Herausforderungen mit denen die Öl- und Gasindustrie konfrontiert ist zeigen uns, dass es notwendig ist, Lösungen zu finden, die zuverlässiger, wirtschaftlicher und robuster sind. Neue Verfahren zum Bohren und Komplettieren von Bohrungen sind erforderlich. Die mechanische Instabilität der Bohrungen zwingt uns, neue Bohrverfahren zu entwickeln. Casing while Drilling (CwD) ist eine der Techniken, die uns noch zuverlässiger und zuversichtlicher bohren lässt.

Der Ansatz von CwD ist, die Verrohrung anstelle eines klassischen Bohrgestänges zu verwenden. Das bedeutet, dass das Bohrloch gebohrt und gleichzeitig verrohrt wird. Wenn auch bis zur Gesamttiefe (Total Depth, TD) gebohrt wird, wird die Verrohrung an Ort und Stelle zementiert. Unkonsolidierte Formationen mit Tendenz anzuschwellen und auszubrechen, sind für diese Vorgehensweise am besten geeignet, ebenso wie Verlustzonen.

Dieses Bohrverfahren hat mehrere Vorteile gegenüber herkömmlichen Bohrverfahren. Es reduziert die Gefahren, die mit oftmaligem Aus- und Einbau von Gestänge einhergehen. Bohrspülungsverluste werden verringert und eine höhere äquivalente Zirkulatonsdichte (Equivalent Circulating Density, ECD) kann mit dem gleichen Spülungsgewicht erreicht werden. Dies ist möglich, weil das Bohrklein im Ringraum von Schlägen der Verrohrung zerkleinert und in die Gesteinsporen gedrückt wird und die Poren dadurch verstopft werden. Insgesamt verbessert dieses Verfahren die Effizienz des Bohrvorganges durch die Reduktion von unproduktiver Zeit (Non-productive time, NPT).

CwD ist seit geraumer Zeit im Einsatz und das Verfahren und seine Einsatzmöglichkeiten sind bekannt. Diese Technologie kann mit den heutigen Anlagen mit wenigen oder sogar ohne Modifikationen verwendet werden. In Abhängigkeit von der Nutzung, können wiederverwendbare und nicht-wiederverwendbare Bohrgarnituren (Bottom hole assembly, BHA) und Bit-Systeme eingesetzt werden.

In dieser Arbeit wird das Bohren mit CwD & Liner while Drilling (LwD), verbunden mit der technischen Machbarkeit bei OMV Pakistan diskutiert. Diese Arbeit wird verfasst, um die bestmögliche Übereinstimmung zwischen den Anforderungen des Unternehmens und der Verfügbarkeit von unterschiedlichen Geräten von diversen Service-Providern auf dem Markt zu finden. Schließlich wird ein neues Bohrloch "Miano NN" entworfen und es erfolgt eine Kostenanalyse um die Anwendbarkeit des Verfahrens im laufenden Betrieb des Unternehmens zu beweisen.

Executive Summary

This dissertation aims at planning a well using Casing while Drilling (CwD) technology from the already existing wells in the Miano field for OMV Pakistan GmbH. This is based on the motivation to reduce risk and delivering the well in shorter time and less cost. Offset wells are used to plan a new well.

This thesis describes the introduction to the technology, its evolution with time and different levels of casing and liner drilling technology. This document further explains different types of retrievable & non-retrievable systems available in the market and latest technologies which are applicable for wide range of applications ranging from surface to production casings and onshore to offshore applications.

It further describes the benefits we can have from CwD techniques. It explains how we can save time and cost while drilling a well. This also shows the casing and connection design considerations required for better operational design. Section 4 and 5 of this document includes technology considerations and applicability analysis of this technology for the operations in Miano Field.

Three scenarios are described. Detailed feasibility of engineering work on landmark software for our prognosis well is made. Torque and drag calculations & hydraulic design is made. Available equipment in the market is referred to be used to make the plan and to generate authorization for expenditure (AFE) of proposed cases.

Economics of each individual case along with time vs depth curve is made. Cost comparison between all three cases is done and major costs saving operations are described.
In the end conclusions and recommendations are made regarding its applicability in the field.

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1.0 Introduction

1.1 Overview

Casing while drilling (CwD[1]) also known as Casing Drilling[2] or EZ Case[3] is becoming popular emerging technology in oil and gas wells drilling now-a-days. This technique eliminates the use of drill pipe for drilling. The well is drilled using a standard casing in-place of a drill string and this casing is then cased and cemented when it reaches the TD. Bit is installed beneath the casing string and it drills the formation in the conventional way. This is shown in *Figure 1.*

The use of casing drilling saves rig time as a whole because there are no or less drill pipe tripping. The basic purpose for using this technology is to reduce cost and improve well bore stability in unstable formations [1]. The overall drilling time is reduced. Safety of the crew is improved due to less pipe handling. Crew size can be limited due to fewer requirements of hands on work. Use of casing drilling reduces the risk of stuck pipe. Small annular size results in more velocity inside the annulus. ECD of the mud increases a little in this case but it does not cause any negative effect [2].

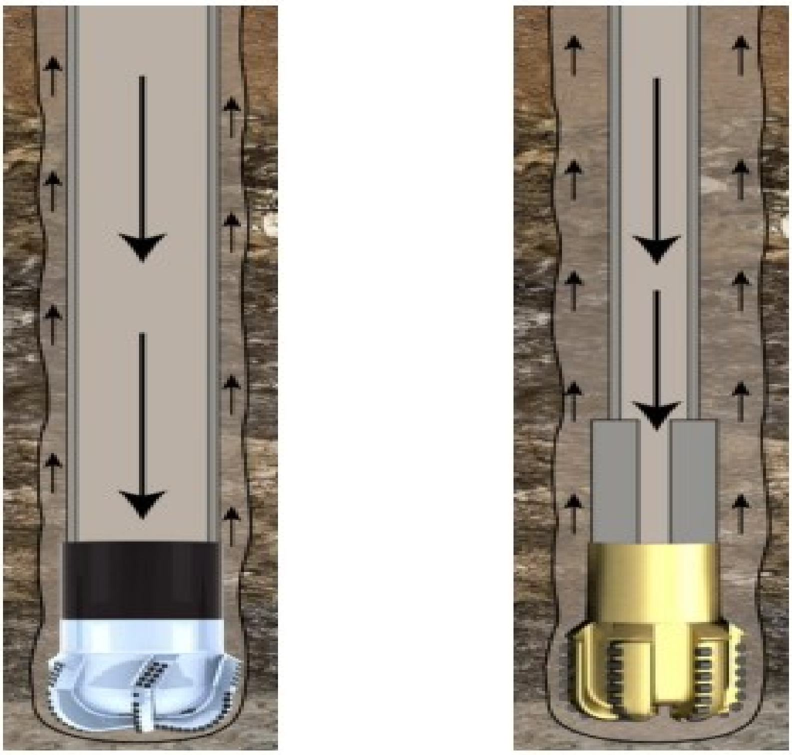

Figure 1: Non-retrievable CD assembly & Conventional drilling assembly [1]

[1] is the trademark name of Weatherford

[2] is the trademark name of Tesco

[3] is the trademark name of Baker Hughes

Advantage of drilling with casing is that it keeps every foot drilled. If everything is good then casing can be set deeper. Casing while drilling helps in mechanically strengthening the borehole wall. As the annulus size is less as compared to traditional ways of drilling. So, casing rotation causes a ‘plastering’ effect [3]. This effect is also known as smear or stress cage. According to this theory, casing strikes against the borehole wall and pushes the cuttings back into the fractures of the formations. It fills the small cracks and crevices thus reducing the filtrate loss and loss of whole drilling mud into the formations. It is a viable alternative for drilling in depleted or mature fields that have severe loss circulation and stability problems.

While in conventional drilling, depleted formations may require extra casing strings to avoid well bore stability problems. Using Casing Drilling the number of casing strings needed may reduce because of improved wellbore stability and reduced contingency [2]. In conventional drilling, excessive cuttings may come to the surface while drilling, due to unstable wellbore. Reaming and conditioning of well is required thus wasting lot of time and increasing the NPT. The time can be saved during Casing Drilling. Hence, saving the well construction cost.

The important aspect of this technology is that it can be used with the same drilling rigs and the same top drive equipment without any extensive modification. Only few extra components are required. In the simplest case only some of the extra components are required and donot require any rig modification. Using this technique allows drilling of a wide range of hole sizes. Drilling bits and BHA can be retrievable or non-retrievable. The retrievable bits can be retrieved by drill pipe or wireline while non-retrievable bit can be drilled through, by the help of any oil field standard PDC bit during the next bit run.

1.2 History

Oldest known casing drilling techniques goes back to the end of nineteenth century. In 1930’s Russians founded a way towards retrievable bit without tripping of pipes. In the mid of 20th century: Brown oil tools made the surface and downhole tools for the Casing Drilling operations. The technology cannot make it into the market because of less ROP and dilemma in industry for slow change.

Tesco Corp. in the beginning of 1997 developed their Casing Drilling (CD) system. TESCO along with BP drilled 15 wells with depth ranging from 8300 to 9600 ft. in the Wamsutter field, Wyoming, USA.

By the end of this venture, TESCO was able to demonstrate the world that CD is an efficient and effective way to drill the well with penetration rates as much as conventional drilling. One of the well drilled with CD in that field was the third fastest in the field. Great technological improvements were made in CD overtime but it was obvious that exploration companies would only imply if it would be compatible with already existing rigs. One other big challenge was to introduce the horizontal and lateral drilling using CD. Now a day, CD is grouped into four levels which will be discussed later-on.

Casing Drilling has found its way in off-shore environments as well. Weatherford drilled nine-string multi-conductor batch faster than the typical time taken to construct eight conventionally drilled conductors, in offshore New Zealand [4]. After the first two stove pipes were drilled up to 87 ft. in depth, the remaining seven wells took almost 23 hours each for drilling and cementing.

Newest Drilling with casing (DwC) bit from Weatherford i.e. Defyer is designed to extend DwC in harder, deeper and longer intervals. The new bit which eliminates dedicated drill-out trips has 80% less steel in the drill out path thus making it possible to drill the Defyer bit with any PDC bit without requiring any round trip. It takes less than 30 min to drill such a casing drilling bit [5].

1.3 Casing drilling levels of technology

Casing is used as a drill string in Casing Drilling(CD) applications. Now a day, CD is grouped into four levels. Level 1 consists of casing string and a reaming shoe or bit to reach the bottom of already drilled borehole. Level 2 consists of drilling new well with a casing and non-retrievable drill bit having no directional capability. Level 3 has a retrievable BHA that can be retrieved with coil tubing or wireline or jointed pipe without tripping casing again. Level 4 is designated to liner drilling [6]. This is shown in *Figure 2.*

1.3.1 Level 1

Level 1 consists of casing string and a reaming shoe or standard bit to reach the bottom of already drilled borehole. It’s simply running in the casing and cementing it after the normal drilling operation with conventional BHA is completed.

1.3.2 Level 2

Level 2 is non-retrievable bit and BHA for casing drilling. It consists of drilling a well with a casing and non-retrieving drillable bit with no directional capability. Special drillable alloy bit is used. This system is mostly driven by Casing Drive System (CDS) and is rotated from the surface. Drilling fluid is circulated same as in the conventional drilling. The casing can be cemented immediately after reaching the TD. To drill the next section, drillable PDC bit of this section is drilled out with any oil field standard PDC bit.

1.3.3 Level 3

Level 3 equipment offers fully retrievable bit and BHA components. It includes directional wells drilled with fully retrievable BHAs and drill bits augmented by expandable under-reamers. One successful offshore application involved drilling through depleted zones to reach virgin reservoirs. The technique protected the well integrity as it penetrated the depleted zones, and reduced pipe sticking considerably. Drilling performance is judged in two ways: in surface holes it is penetration rate-based; in the remainder of the borehole sections it is based on non-productive time (NPT).

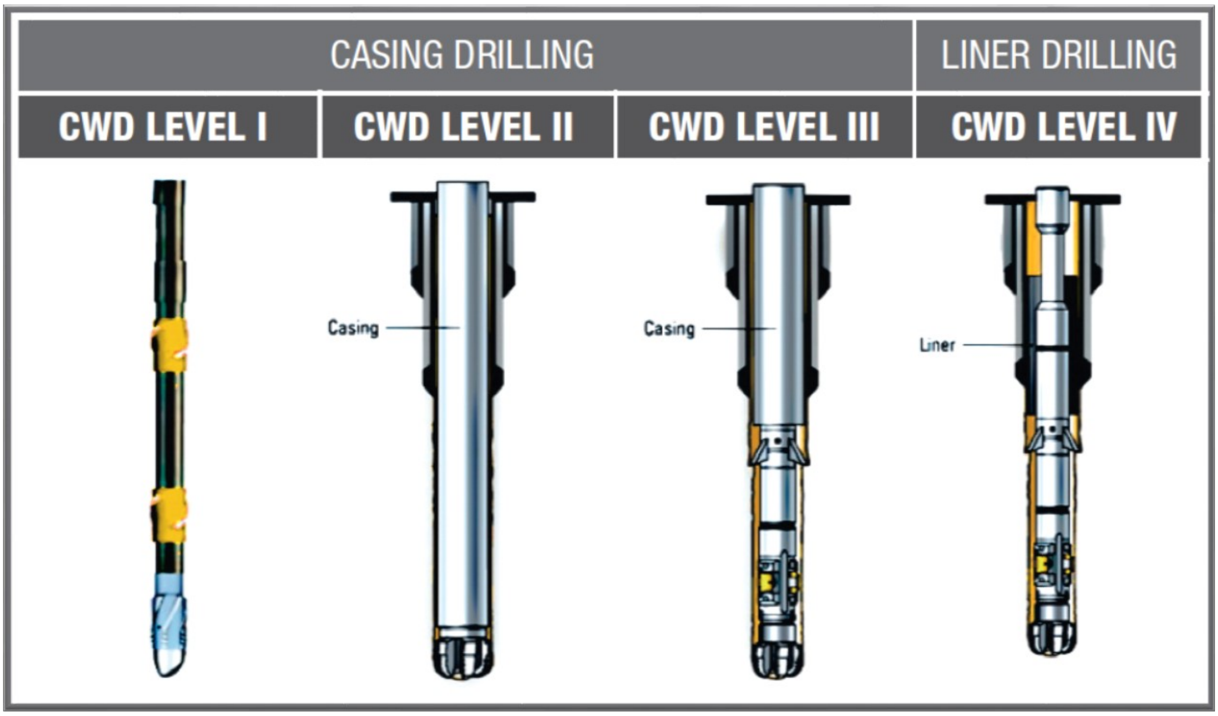

Figure 2: Casing and Liner Drilling Level category [6]

1.3.4 Level 4

Liner drilling is characterized as Level IV drilling. In simplest Liner drilling technology, drillable bit is attached to liner and is run with drill pipe with hanger & float collar already installed. Second level liner drilling has retrievable BHA system attached with the last liner joint. Third level liner drilling tools have BHA run on drill pipe inside the liner. Torque is given to the drill pipe and is not fully transmitted to the liner joints thus, saving them from excessive fatigues and cyclic stresses.

1.3.5 Proven Advantages of CD over conventional drilling

Some of the most typical advantages of CD which are known until now are:

- Reduced use of Drill pipe
- Reduction in trip time

- Smaller Crew size
- Straighter holes drilled
- Reduction in Stick pipe incidents
- Fewer fishing jobs
- Less power requirements on rig
- Overall reduction in drilling cost
- No loss of footage at TD
- Deeper casing points
- Fewer casing strings required
- Increased safety at rig site
- Reduced accidents
- Overall reduction in drilling time
- Reduced capital and logistics costs
- Reduction in rental equipment
- Reduction of safety related incidents and accidents
- Elimination of pack-off and tripping related problems

1.4 Basic changes/improvements required

For implementing CD we must make improvements in the following systems:

- Top drive should be more robust
- PDC cutters have to be used
- Robust casing connections & accessories are required
- Special equipment for retrievable BHA is required
- Casing drive tools should be available
- Downhole tool designs may need to be modified

2.0 Casing & Liner Drilling Systems

There are two types of casing drilling systems. One is drillable bit system and other is retrievable BHA and bit system. Depending on the selection of equipment and company selected, CD can be used in drilling a vertical or deviated well.

2.1 Weatherford DwC™ and DwL™ System

DwC system is a registered trade mark of Weatherford international. They have 2 types of bits which they offer in the market.

2.1.1 Defyer™ Drillable Bits

Defyer is a drillable custom designed casing bit and can be used in any environment. The bit is installed with PDC cutters and is able to perform in temperatures up to 400°F (200°C). Defyer bits can drill in a wide range of formations from soft to hard rocks and can be drilled out with any PDC bit while eliminating the dedicated drill out trips. Nomenclature of Defyer DPA series is shown in *Figure 3.*

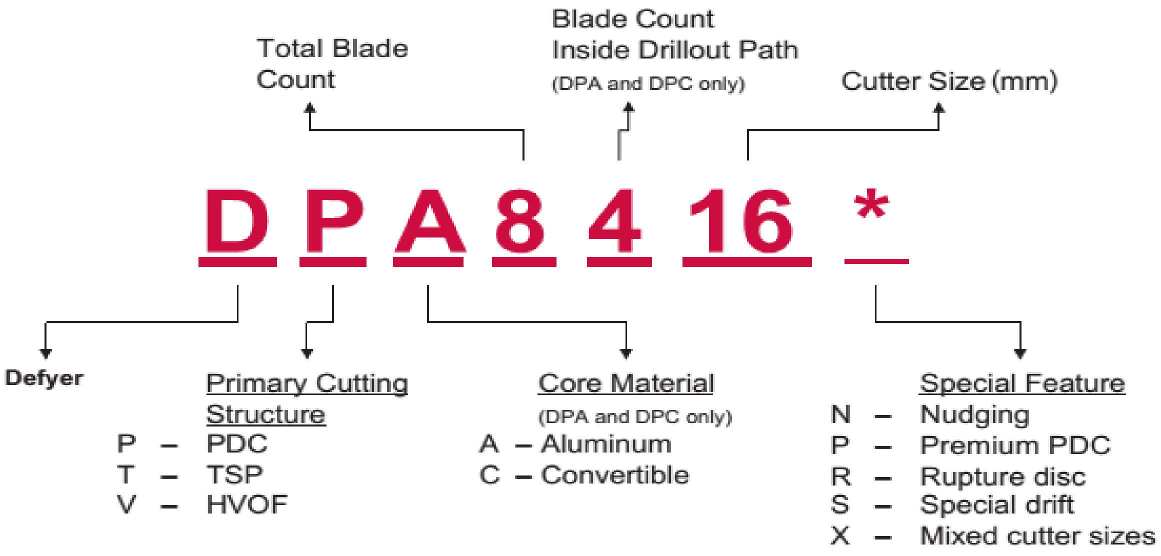

Figure 3: DPA bit nomenclature [5]

The construction of casing drilling (Defyer DPA) bit is done with 80% less steel in the drill out path and has been drilled out in less than 30 minutes without imparting damage to the conventional PDC bit which is intended to drill the next section. It is shown in *Figure 5.*

2.1.2 DwL™ system

Weatherford has non-retrievable drilling with liner system. Bit is directly attached to the liner and is run through drill pipe. Torque is given to the drill pipe from the top and whole string rotates. Liner is run with the float collar and hanger assembly. When section TD is reached cementing is done immediately. Hydraulically actuated hangers as opposed to mechanically actuated hangers are used for DwL applications. Hangers should be robust enough to withstand several hours of rotation and in the same time should not affect hydraulics of the bore hole.

2.1.3 Equipment associated with DwC™

Although DwC eliminates the use of BHA rental equipment but several other specialized tools may be required which are offered by the company.

Figure 5: Drillable Defyer Bit [5]

Figure 4: Over Drive Tool [5]

a) Over Drive™ tool

Over Drive casing running tool replaces many conventional tools. Power tongs, elevators, bails, fill-up and circulation tool are integrated into one tool. This system is integrated with any top drive and enables simultaneous rotation, reciprocation and circulation of casing string. It also eliminates the need of conventional tongs, elevators and related personnel. It is shown in *Figure 4.* This also applies to pushing, rotating and circulating the casing string for DwC in high angle and extended reach problematic wells. Over drives are of two types, external clamping and internal clamping. For 9-5/8” and higher casing diameters internal clamping is required and for smaller diameters (3-1/2”-9-5/8”) external clamping is required. Detailed specs sheet is attached in ***Appendix A.***

b) CleanReam™ Casing Reaming Shoe

If reaming is required the CleanReam shoe is installed below the last casing joint which reduces time required for reaming. This reaming shoe is advantageous in the places where problems are high. An aggressive cutting structure enables reaming through tight spots and hard ledges. The flow during penetration can be manipulated with interchangeable nozzles to enhance hole and blade cleaning.

c) Rubber-Lined DwC™ Centralizer

To keep the casing centralized during cementing, a rubber lined DwC centralizer is used. The advantage of using that is to provide extreme durability during the operations. The rubber lined centralizer reduces casing wear with reduced friction and optimized fluid by-pass. The installation is safe and simple due to its light weight design.

d) Torque Ring

The torque rings are easy to install and substantially increases the torque rating of buttress, STC or LTC connections. They are not required with metal to metal seal casing joints. Torque ring is shown in blue color in the joint shoulder in *Figure 6.*

Figure 6: Torque rings [5]

DwC performance from Jan, 2000 until to date is quite impressing as it has helped over 40 operators globally with more than 1500 jobs with non-retrievable system. DwC has until to date drilled more than 300,000m of depth with pipe dimeter of 4-1/2" to 24". The achieved success rate is around 98%.

2.2 Schlumberger TDDirect system

Since 1998, TDDirect system is used to drill more than 1450 wells, 1 million m and wells as deep as 15,500 ft. TDDirect system has proven its applicability in directional drilling and wide range of inclinations. This system has reduced the time needed for drilling by more than 30% and has proven to reduce NPT.

TDDirect system can be used at any interval. Direct XCD drillable bit drills vertical sections in single run. TDDirect CD system is used for the wells which have to be logged or directionally drilled. TDDirect LD system can be used with XCD bit or directional BHA when liner drilling is required.

2.2.1 TD Direct system

Direct XCD drillable copper bronze alloy bits are used in vertical rotary drilling applications. As the bit drills to TD, it serves as a casing shoe. Floats are already placed in the casing before running. After cementing the bit is easily drilled with any oil field standard PDC bit. Same bit can continue drilling ahead without dedicated bit change trip. Alloy bit used has following characteristics as shown in *Figure 7.*

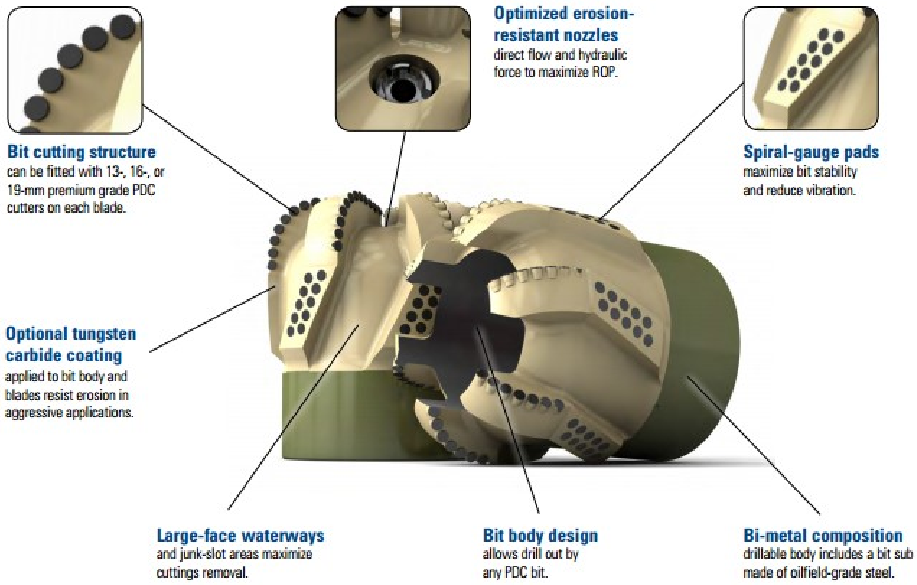

Figure 7: SLB drillable casing bit [7]

2.2.2 TDDirect CD system

TDDirect casing drilling system can be used with a retrievable BHA. Using retrievable BHA, allows us to use LWD and MWD systems along with RSS motor. These wells can be drilled both vertically and in deviated hole intervals without retrieving back the BHA assembly.

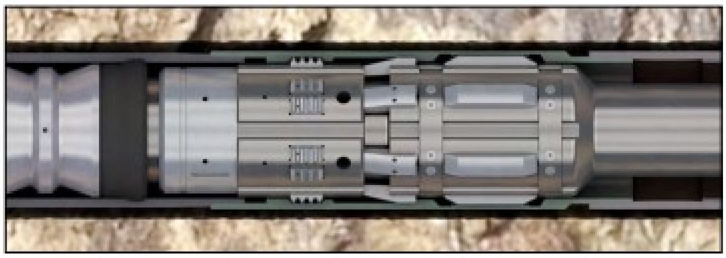

Figure 9: The DLA seals and connects the BHA to the casing string [7]

Drill-lock assembly (DLA) connects the BHA to the bottom of casing shoe joint as shown in *Figure 9*. Downhole motor provides rotation to the bit and BHA. Surface rotation can also be provided by the top drive simultaneously.

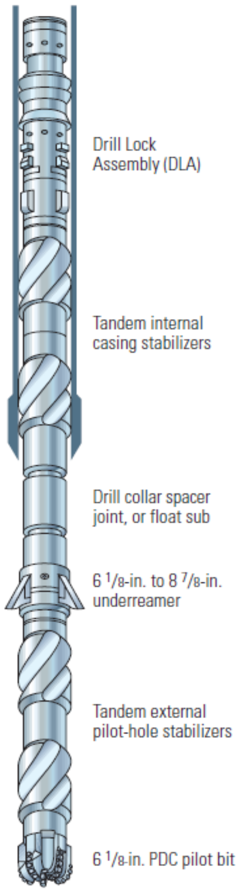

Figure 8: Retrievable BHA assembly [7]

2.2.3 TDDirect Liner drilling system

Liner drilling assembly has three major types. Non-retrievable type is same as described in WFD section. Remaining two types are retrievable. They are a result of collaboration between Schlumberger and Tesco.

a) Simple BHA retrievable assembly

The retrievable BHA for vertical or deviated wells requires a small bit with rotary motor installed below it. Bit drills a pilot hole which is further opened by under-reamer with expandable cutter pads. Stabilizers between pilot hole and under-reamer maintain inclination. Upper stabilizer, located inside the liner string reduces BHA vibrations and protects DLA. It seals against the casing to direct drilling fluid through the bit. BHA is positioned such that all components below the tandem stabilizer extend into the open hole as shown in *Figure 8*. The DLA is run on wireline and landed in to its assembly near the bottom of the casing. In simple BHA, liner is directly rotated through the running tool (drill pipe) and all of the liner length gets the torque [7].

b) Multi-set BHA retrievable assembly

Hanger liner multiset capability enables the liner to be suspended at any point during drilling. It has a unique multiset liner hanger that allows the liner to be parked in tension inside the parent casing or any other section at any point during drilling. After a return trip from surface, drill string is locked into the liner and hanger is unset for continuing drilling. Drilling has to be stopped for hanger setting because this works with ball drop.

TDDirect LD system internally bypasses the liner with drill pipe. It directly provides the torque to the bit. The liner connections are only subjected to the friction that is generated by the rotating liner in the well bore. BHA remains the same only difference is that in Multi-set BHA, torque is given to the DP from the top and it is latched to Liner through DLA near the bottom. Liner is not exposed to the torque directly along the whole length.

Plug landing nipple (PLN) is pre-installed in the casing string and pump down displacement plug is then launched into the PLN.

2.2.4 Equipment associated with TDDirect™

Several equipment are associated with TDDirect system. They are described below.

a) Displacement plug cementing system

Provides cement isolation and back flow prevention. This system includes a plug landing nipple (PLN) which is pre-installed in the casing string and a pump down displacement plug (PDDP). Cementing of the casing begins as the casing reaches the TD. The PDDP is launched after the tail slurry and locks into the PLN. The PLN wipes the casing or liner and provides the barrier between the cement and displacement fluid. Upon landing, it prevents the U-tubing of the cement.

b) Hydro-formed casing centralizer

This type of centralizer provides the centralization to the casing and on the other hand it promotes plastering effect. It also helps in good cement bond and helps protect well integrity. It has hard faced and non-hard faced types.

c) Multi-Lobe Torque (MLT) rings

Multi-lobe torque rings provide a positive makeup shoulder to increase torque capacity when installed in standard API buttress threaded connections. Increased torque capacity prevents tool joint from being overstressed in drilling and work-over applications. This is shown in *Figure 10*.

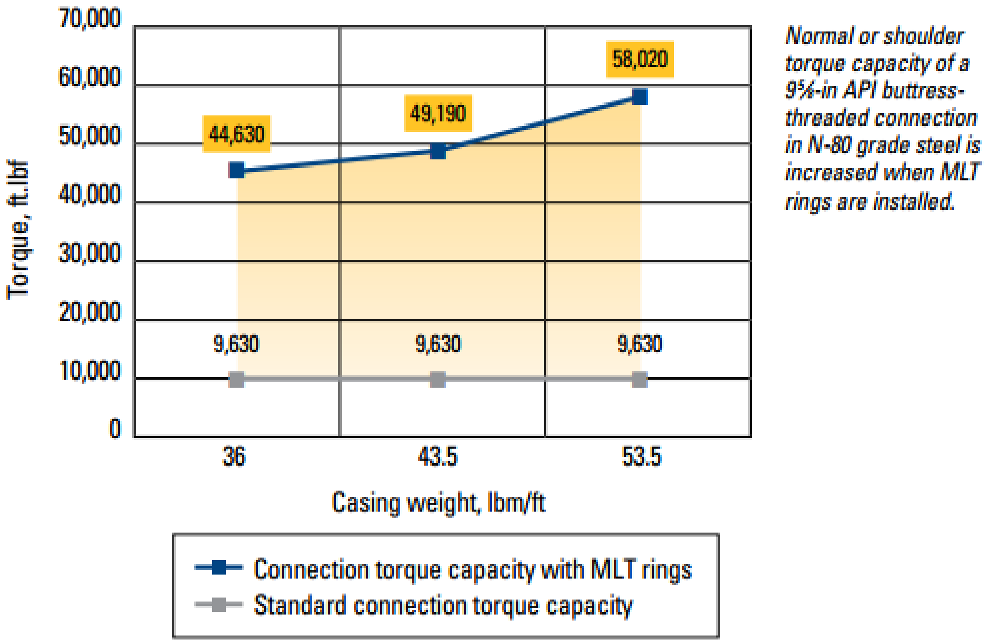

Figure 10: Torque rings increase the torque capacity of casing [7]

2.3 Baker Hughes EZCase™ system

EZCase™ casing bit system is present in the market for casing drilling and liner drilling operations. Industry exclusive steel crown with full PDC cutting structure enables casing drilling operations in one run. Genesis™ PDC bit ensures drill out by any PDC bit.

2.3.1 SureTrak™ Steerable Drilling Liner system (SDL)

SureTrak™ steerable drilling liner service enables operators to reach reservoirs, evaluate the formation and place a liner to TD in single run. Baker Hughes Rotary steerable system along with LWD and MWD tools help steer the casing or liner at any point.

2.3.2 Hybrid SureTrak^{TM} SDL system

A standard drill pipe is used as the inner string of the SDL to handle drilling torque and to trip the drilling BHA. The liner is isolated from the reamer shoe and can be rotated from surface at a much lower rpm than the pilot bit and hole opener. As a result, the load on the liner is reduced and fatigue life of liner is improved [8].

2.4 Comparison between Non-Retrievable and Retrievable system

There are two systems available in the market; Retrievable and non-retrievable bit and BHA systems. Both these systems have their own applications and limitations. Application of these systems varies from field to field. A good design needs to be made and implemented for the acceptable results. Advantages and dis-advantages of both these systems are given in *Table 1.*

Table 1: Comparison between Retrievable and Non-retrievable system

Non-Retrievable system		Retrievable system	
Advantages	**Disadvantages**	**Advantages**	**Disadvantages**
Low cost	Limited directional control	Ability to steer	High cost
Simple to operate	Cased hole logs only	MWD/LWD capability	More complicated to set up and operate
No rig modifications required	Limited casing shoe selection	Wide range of bit selection to suit formation and distance	Rig modification required
Zero risk of irretrievable tools in the hole		Possibility to change the BHA and bit	Risk of losing expensive tools in the hole
Cementing can commence immediately upon TD			Unable to cement immediately upon TD

2.5 Drilling with casing Applications

- Very soft surface hole formations to deep production casing strings
- Conductor or surface strings in a single run
- Brown fields and depleted intervals
- Drill with liner through trouble zones
- Regions where running casing near or at TD is major issue
- Isolate losses, pressure or unstable hole intervals by drilling through and simultaneously casing the trouble zone
- Reaming casing or liners through unstable hole conditions, excessive caving’s or in severely swelling or mobile formations

3.0 Drilling with casing: Key Drivers

Casing drilling has some advantages over conventional drilling which makes it more popular and more usable day by day. It has its application in both onshore and offshore drilling. Recent developments have further widened its applicability in deviated and horizontal wells. Liner drilling has also proved its applicability while showing appreciable results in offshore environments.

3.1 Reduction in drilling flat time

One of the benefits of Casing drilling is saving time. Tripping pipe and running casing with mud circulation includes lot of time which can be eliminated by using this technique. There is a time saving potential of 12%, assuming 3.5 min for 100ft drill pipe and 5min for 40ft casing with an on bottom ROP of 50m/hr, saving potential increases to 18% for an ROP of 100m/hr. this is shown in the *Figure 11* below.

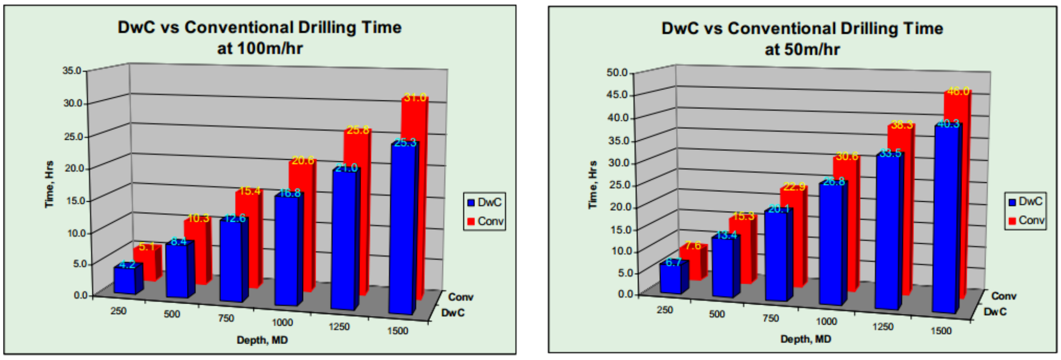

Figure 11: Potential Connection Saving Time [9]

The figure shows saving time for connections only. Actually using this technique also helps in removing non-productive times. Stabilizing heaving and sloughing formations, caving in’s and pack-off which may take lot of time. Adding LCM, reaming, circulating hi-vis pills and conductor clean out runs etc are also some of the NPT events. Typical total time savings of 30-50% are observed in certain cases [9].

3.2 Wellbore strengthening

One of the most important aspects of casing drilling is the fact that we have a better handling of lost circulation zones. Formation cuttings and filter cake are plastered into the wellbore wall to seal of fractures and stop drilling fluid losses. This effect is accelerated by designing a lost circulation material that is mixed with small cuttings. This phenomenon is known as plastering or smearing effect. The result is an ideal particle size distribution for lower fluid loss rates as shown in *Figure 12.* This result in a stronger wellbore and a wider mud weight window as the trouble zones are sealed off and potential kicks are prevented.

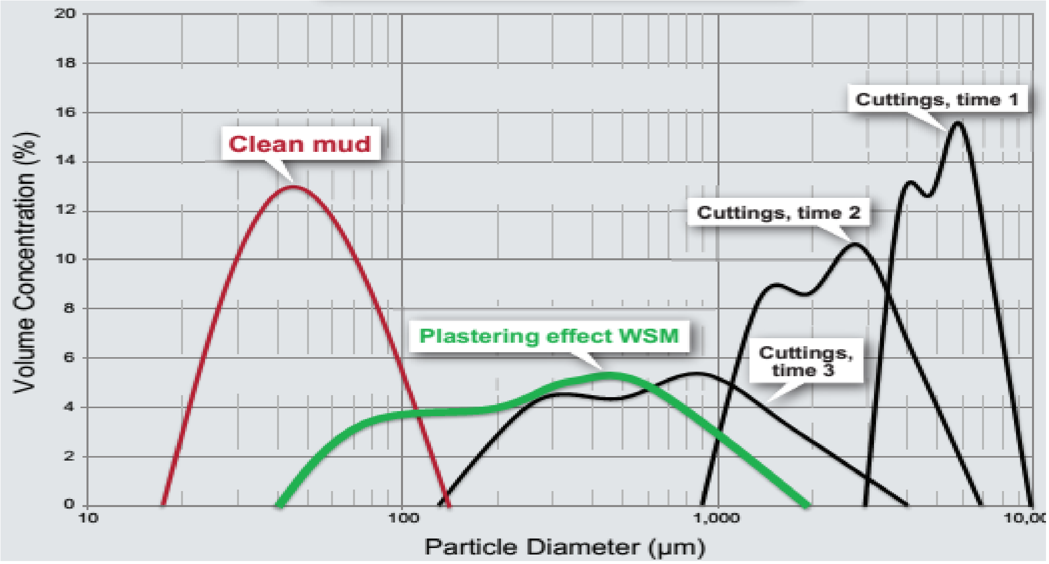

Figure 12: Particle Size Distribution [10]

There is an industry accepted ratio of casing diameter to bore hole size which is approximately 0.8. This aims at providing the optimal annular pressure and plastering effect due to casing side loads. This has been illustrated in the *Figure 13.*

During this plastering effect the cuttings are broken down into smaller particle sizes. This results in higher concentrations of smaller particles. Although this grinding effect is uncertain and takes time but it is assumed to be so. The black lines show the grinding effect in *Figure 12.* Plastering effect as indicated by green line, create the optimal conditions for the wellbore strengthening materials (WSM). The increased concentration of small size particles may result in increase in colloidal particles concentration which might not be easy to remove from the mud.

Figure 13: Plastering effect in wellbore [5]

3.3 Elimination of tripping related problems

Tripping of tubulars inside the open hole can cause surge & swab effects, lost circulation and key seating. This may results in borehole in-stability and well control incidents. Elimination of pipe tripping results in the prevention of these problems.

3.4 Getting Close To TD

Casing drilling eliminates drill pipe tripping and casing running problems. So, it eliminates time dependent wellbore deteriorations. Casing being on bottom ensures that wherever the casing TD is, it can be cased and cemented there. So, there is no concern of stuck BHA and lose of expensive equipment in the wellbore thus not reaching the TD.

3.5 Drilling In Mature Fields and Optimizing Lost Circulation

Brown fields sometimes have a problem of severe lost circulation in reservoir sections and in fractured formations. This can result in some more serious problems i.e. stuck pipe. Thinking for an instance, one would say that it’s not a good option to get the casing stuck before reaching the planned TD. It seems that problem of lost circulation and higher ECD would be a bigger problem (in casing drilling) due to small borehole size and higher frictional losses in borehole. In actual, the losses are noted to be reduced. Although exact mechanism is not yet known but it can be regarded to plastering effect building impermeable filter cake.

The proven experience shows reduction in loss circulation and stuck pipe tendency. This when coupled with well control issues gives the compelling argument that well is much easier to control when bit is on bottom, so do in casing drilling. So, it should be the first choice of use in these difficult zones.

3.6 Enhanced Wellbore Quality

Stiffness of casing string results in a less tortuous hole. It provides a smother wellbore and reducing the risk of key-seating and mechanical sticking. Stiff assembly is also less prone to vibrations and reduces impact damage to wellbore and the bit. Oval shaped holes are formed in case of drill string vibrations which is not a case in casing drilling.

3.7 Enhanced Safety

Safety at work is improved by using casing drilling technique. Less handling of pipes, less tripping, less handling of equipment and less well control issues have resulted in making it more safe application. In offshore applications, deployment of divers is reduced and sometimes eliminated. Hammering, loading and rigging pile hammers is often considered the most hazardous operation on rig floor offshore. These are reduced and sometimes eliminated by using casing drilling applications.

3.8 Cost saving

Conventional drilling requires the need of rental BHA equipment which can be eliminated by using casing drilling. Reduction in time for drilling can save lot of money and even lot of investment. Saving potential of casing drilling over conventional drilling in terms of time can be as much as 50%. Drilling wells with less or no NPT means delivering the well on-budget and on-time [1].

3.9 Casing

Casing has an important place in well design considerations. Casing is basically used for isolation purposes of our borehole from the bare formations. It is used to prevent the borehole from caving-in during drilling of a well.

3.9.1 Casing design considerations

Conventionally, we drill a well and then we run the tubular casings. The casing is then cemented and allowed to settle to provide additional support and pressure tight seal.

For casing drilling our approach is different. We drill with the casing and then cement it. So, casing has to be tough enough to withstand all the dynamic loads and still capable enough to be set in the wellbore for lifetime; aiming at providing us the required seal and integrity.

While doing casing and tubing design following considerations should be kept in mind.

- Ensuring the well mechanical integrity
- Optimizing well cost
- Providing maximum allowable working window to operations personal to conduct further operations

One or more of the following strings are required in every well. So, for casing drilling or liner drilling each of the following string has to drill the formation and also has to act as a barrier for its lifetime.

- Structural casing
- Conductor pipe
- Surface casing
- Intermediate casing
- Liner strings
- Production casing/liner

Basic material properties

Stress: stress is defined as load acting on a cross sectional area

Strain: change in length per unit original length of pipe

Yield Strength: it is the stress above which irreversible plastic deformation occurs

Young’s modulus: it defines modulus of elasticity which relates stress with strain as long as they are proportional.

3.9.2 Design factors

The casing string is designed from inside to the outside and bottom to the top.
There are 8 major design factors on which tubulars are designed:

- **Collapse:** tubulars should maintain integrity with high annulus pressure with little or no internal pressure support.
- **Burst:** tubulars should maintain integrity of the casing when there is high internal tubing pressure and little or no annular support.
- **Tension:** tubulars must withstand its own weight. It should also withstand additional loads when pulling out, setting packers and changes in the environment due to temperature and pressure variations. Tension can be caused due to buoyancy or thermal expansion or borehole friction. Drag and slack-off can also cause tension or axial loads.
- **Compression:** tubulars must withstand compressive loads when setting packers and in highly deviated wells or doglegs where there is possibility of weight support through ledges. Casing below the neutral point are considered to be in compression and collapse loads need to be considered while designing.
- **Corrosion:** tubulars must be designed to counter the corrosion effects of the fluids in the environment in which it is placed. Fluids can be the produced hydrocarbons with its impurities, acidizing fluids, fracking fluid, salt water and/or corrosive gasses.
- **Coupling:** couplings are considered as the weakest parts in the casings. So they should be free from leaks, properly screwed (but not over torqued), should maintain strength both in tension and compression loads.
- **Abrasion/Erosion:** tubulars should withstand erosion and abrasion loads during their life time. This erosion may arise from produced fluids, hammering and handling of equipment or presence of impurities while manufacturing.
- **Stimulation loads:** tubular should withstand excessive loads arising from pump pressures, acidizing, fracturing and other stimulation jobs.
- **Tri-axial loads:** tri-axial stress is not a true stress. It’s a way of comparing a generalized 3-dimentional stress state to uniaxial failure criteria (i.e. yield strength). The tri-axial stress is called as von-Mises stress.

- **Buckling:** casing is hanged straight down in vertical wells or it lays on the lower side of the hole in deviated wells. Compressive loads may be induced due to thermal and pressure loads due to which the initial configuration may become unstable. In a vertical well, helical or coil shape bucking may occur under these circumstances.

3.9.3 Casing connections considerations

Connections represents less than 3% of pipe length yet more than 90% of pipe failures are at the casing connections. Most of the failures are due to improper designs, loads exceeding the rated capacity, incompliance to makeup torque recommendations, improper handling and damages during operations. Yet connections represent 10-50% of total tubular costs.

STC (short thread connection)

It has 8 threads per inch. Threads have rounded crests and troughs. STC is better for shorter length casing applications. They are not used in wells where high axial loads or bending loads are anticipated.

LTC (long thread connection)

It has 8 threads per inch. Threads have rounded crests and troughs. Thread section is longer and has better seal-ability and tensile strength than STC.

BTC (Buttress threads connections)

It has a square thread with a flat crest and trough and five buttress threads per inch. It is an excellent thread connection with higher loads and moderate internal pressure and temperatures.

MTC (Metal to Metal seal thread and coupled)

They provide gas seals and are shoulder to shoulder connection. They are the premium connections and are specially designed for HP/HT and zones where seals are required.

4.0 Technology considerations and previous experiences

In order to evaluate the applicability of casing drilling and liner drilling we have to keep in view certain aspects of technology which makes it advantageous. There are many points of consider before giving a final green signal for its applicability. Experiences and previous case studies also help in finding out the best `fit for purpose` application. The feasibility study is done for Miano field in Pakistan.

In OMV Pakistan fields the company is interested to drill vertical wells using casing drilling and liner drilling applications. All the available technologies in CD and LD are discussed in Chapter 2.0. According to the availability of the equipment with-in the country and required expertise only Weatherford offers the services. Only available equipment is the rotary non-retrievable equipment. So, non-retrievable vertical well Weatherford equipment is the only option. The detailed analysis for the selection of the equipment is given below.

4.1 Applicability Analysis

Below are some of the aspects which need to be kept in mind while planning a casing or liner drilling job.

- Geo-mechanical study for formation strength
- Bit reports (offset wells)
- DwC drill bit selection
- Casing and connections
- Drilling parameters (offset wells)
- Hydraulics
- Torque and Drag (T & D)

4.1.1 Geo-mechanical study for formation strength

Miano field offset wells were analyzed to see the behavior of the formations. Ghazij formation at the depth of 812-1415m was found to be unstable. Severe losses were observed in Sui main limestone (SML) formation which is present just below Ghazij (well prognosis is given in ***Appendix C***).

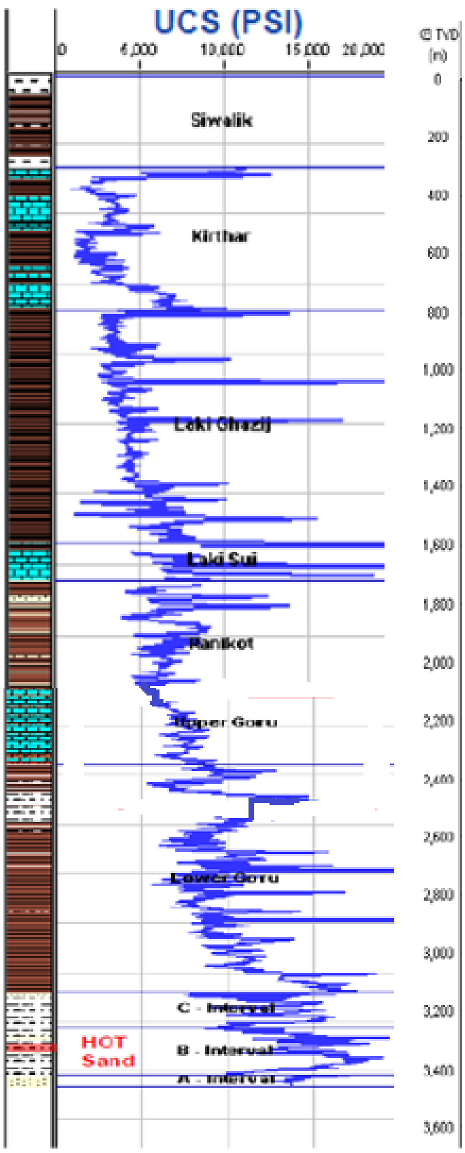

Figure 14: UCS report of Miano Field

In some of the wells additional wellbore stability issues occurred. These events are most likely caused due to the fault line presence near the wellbore wall.

a) Lost circulation

Most of the offset wells in the vicinity of Miano NN were drilled with low mud weights between 8.33 ppg and 10.5 ppg EMW. In most of the Miano wells, lost circulation and severe losses were reported in Sui Limestone (SML).

Keeping in view the casing setting depths requirements, two sections were selected for drilling with casing or liner. While considering the formation strengths to be drilled it was found that most of the formations are in the range of UCS 5,000psi to 20,000psi along the depth of 1000-1500m and 2200-2800m where DwC and DwL are intended to be deployed. UCS from surface to target depth is shown in *Figure 14.*

4.1.2 Bit Report

Bits data's from corresponding sections of wells have been checked and found that in the section from 788 m to 3000 m there was no big damage to the bits and in details it is mentioned below in *Table 2.*

4.1.3 DwC drill bit selection

As mentioned in geo-mechanical study we are expecting formation strength from 5,000 psi to 20,000 psi, which is considered to be within soft to hard formation strength (UCS classification is shown in ***Appendix B***). Offset wells of Miano have been drilled with the PDC bit (e.g. IADC code M422) and it has done excellent job with no major damage to bit. Selected bit for DwC is Weatherford casing drilling series bit which is designed for rocks having compressive strengths of 7-25ksi. Specification sheet of casing drilling bit is present in ***Appendix A*** and IADC code for PDC bits in ***Appendix B****.*

Table 2: Offset wells bit selection

Well	12 ¼” Bit Mfg.	IADC code	Dull grading	Depth, from – to, m	Comments
Miano 9	DSX 134, Reed	-	1-1-WT-S-X-I-NO-TD	939 -1562	No major damage to bit
Miano 14	DSR619M-G8, Reed	M422	1-1-WT-A-X-I-CT-TD	1904 - 3067	No major damage to bit
Miano 8	MDM 629, DDS	M422	2-4-BT-S/T-X-I-CT-TD	788 - 2305	

The drilling bits selected for drilling are all from Weatherford Defyer DPA series. (Detailed specs are present in ***Appendix A***).

4.1.4 Casing Connection

TSH blue connection could be torqued up to 29 kNm. It provides metal to metal seal. The offset data shows that maximum torque encountered during casing running are far less than the final limit. TSH blue connection could hold up to the limit which we will encounter during drilling (without the use of torque rings).

4.1.5 Drilling parameters

Offset wells were taken into consideration for the drilling parameters and following data have been analyzed. Bit damage and connection failure could be the weakest point in DwC. The RPM from offset data show a value of 120 at maximum, Torque is not more than 7000 ft-lbs, WOB does not go beyond 10 ton and ROP shows variable trends and may go up to 30m/hr. From offset data it has been seen that the formation is soft to hard and it could be drilled with PDC bit (specifications of Weatherford Casing Drilling bits are shown in ***Appendix A*** and detailed drilling parameters analysis is done in ***CASE STUDY***).

Hydraulics and Torque & Drag analysis is done in detail in chapter 5 titled “Case Study”

4.2 OMV past experiences

OMV has several experiences of non-retrievable Casing drilling (but not liner drilling) in different ventures. It has mixed outcomes but overall results are satisfactory. Unsuccessful cases are very good from learning point of view and it gives chance for learning and improvement in engineering practices and technology. These experiences are similar to our selected case only in a way that Weatherford non-retrievable bit system has been used. Past experiences show that mostly CwD is used for surface hole drilling. So, this case study is unique as drilling with liner and drilling a deep formation with intermediate casing is never done before in OMV operations anywhere.

Drilling reports and insight into the CwD operations was gained from the engineers working on those projects. Below are some of the experiences of OMV in different regions.

4.2.1 Casing Drilling experience in OMV Austria

a) Casing Drilling key Drivers

Following expectations were linked with this method:

- Reduced time to finish the section, by the time you reach TD the casing is already at TD.
- Reduced risk of casing running problems especially in unstable or unconsolidated formation in the top hole section.
- Reduced losses into the formation which is mainly due to the smearing effect where clay cuttings form a barrier.

b) Strasshof (Appraisal well: June, 2009)

It was the first well for OMV Austria in which they tried casing drilling.

Back ground

- Stove pipe was run down to 23m.
- 17-1/2” hole to 748m was planned with DwC™.
- 13-3/8” J-55, 54.5 lb/ft with BTC connections was planned.

Result

- CwD™ application failed at the beginning of section after 3m drilling.
- No major lost time as 1st CwD™ attempt was immediately suspended and CwD™ during 2nd attempt showed very good ROP.
- During conventional drilling it was decided that CwD™ would be restarted from 500m depth to drill to section TD at 750m.
- Stepwise increase of flowrate to 400 gpm. Tag bottom and casing drilling was commenced with 25 RPM and 3-4 tons WOB. Torque values were 2-3kNm and initial ROP was 2-3m/hr.
- Maximum values of WOB were 10t – 12t, RPM 65 and a flow rate of 660 gpm. Instantaneous ROP values of up to 50 m/hr were observed.

Figure 15: Gravel sticks between blades

Failure analysis of 1st run

- The first meter was without problems and ROP was around 8m/hr. After the first meter drilled, ROP decreased rapidly and drilling went rough.
- Cuttings indicated gravel formation.
- Casing was pulled back.
- First view at the bit indicated unusual bit wear most probably induced by gravel impact.
- A closer look shows two 10cm x 5cm rock pieces at the bit center (*Figure 15*).
- These rock pieces indicated a heavy gravel layer which led to the decision to abandon CwD™ immediately and save the Drillshoe-II for a later stage drilling.

Conclusions / Recommendations

- Casing Drilling in non-conglomerate formations in depths down to 750m is no problem at all.
- Moreover average torque values seen during CwD™ have been lower compared to those seen during conventional drilling.

- For future casing drilling applications, ensure that no casing drilling is required inside the stove pipe.
- Formations in Karpat are very hard but not abrasive, so penetrate it slowly.
- Stage tool operations during 9 5/8” Casing job was fast and trouble free. So, it’s highly recommended for future drilling operations for similar kinds of jobs.
- In the shallow Quaternary of the Vienna Basin gravel layers might be present.

c) Erdpress 25

Back ground

- Well was drilled down to 40m with 12-1/4” BHA.
- WFD DwC™ was rigged up.
- 12-1/4” DwC™ bit was used with 9-5/8”, K55, 36ppf casing having BTC connections and torque rings.

Result

- Operations were started with 270gpm, 50RPM and WOB of 1ton.
- Parameters were gradually increased to 600gpm, RPM of 50-80 and 5ton WOB.
- Overall results were very satisfactory.

d) Erdpress 15

FDE project, Erdpress 15, emerged as a record with 650m drilled (& therefore cased) and cemented within 48hrs. Similar results could be achieved at all other ten wells drilled in Erdpress which resulted in significant time savings.

Total project result

Average time from Spud to Cement in Place is as below:

Conventional Drilling: average 67 hrs. (Without NPT) & average 84 hrs. (With NPT)
Casing Drilling: average 37 hrs. (Without NPT) & average 37.5 hrs. (With NPT)

It is a conservative saving of 30 hours of rig time. This is 1 extra well every 15 wells drilled. At the same time Rig time saved is approximately covering the additional cost spent.

e) Bockfliess 208 Austria (Production well: July, 2015)

Back ground

- Conductor casing was drilled down to 27m.
- CwD™ was planned for next casing section until 500m.
- 16” x 13.375” J-55, 54.5# casing with BTC connection.
- DPA4416 Drillable casing bit with 6 x 12/32” ceramic nozzles fitted.

- Spira-Glider Spiral HD 13.375” x 15.750” was installed 1 per 3 joints.

Result

Well was drilled successfully from 47-500m with on bottom ROP of 27.62m/h, WOB of 5 tons, RPM of 70 and flowrate of 580gpm. Overall results were satisfactory.

4.2.2 OMV New Zealand (Jack-up rig, offshore, 2009)

Background

- 30” stove pipe down to 34m.
- 24” DwC^{TM} conductor pile, TD planned was 325mRT (100m water depth and 40m airgap).
- 26 Joints of 24” casing was estimated.

Result

- Observed leak in 24” casing at connection 24 m below rotary.
- Failed connection is very time consuming to recover from.
- Casing drilling was done and results were satisfactory.

4.2.3 OMV Petrom

OMV Petrom has successfully drilled more than 43 wells with the Weatherford non-retrievable DPA series drillable casing bit. Casing diameters of 9-5/8” and 13-3/8” vertical well intervals ranging from 350m to 900m in length were drilled. Each well was drilled in between 11 to 53 hours depending on length and with an average on bottom ROP of 33m/hr.

Team attained maximum on-bottom ROP of 67.5m/hr and a 354m section in 11.7 hours with an on-bottom ROP of 59.5m/hr. One 344m section which was planned to get 28 hrs took just 14 hours with on bottom ROP of 28.8m/hr and zero NPT. This reduced the drilling time by 47%.

4.2.4 OMV Yemen (Habban Field: Feb, 2014)

Casing Drilling key Drivers

Following key drivers were kept in mind while planning the job:

- Increased safety due to reduced trips and less handling of heavy BHA’s.
- Casing always on or near bottom.
- Allows cementing to begin immediately upon reaching TD (with non-retrievable system).
- Increased chances of better borehole quality.
- Saves mud cost due to reduced loss.
- Minimize axial movements, surge and swab.
- Reduced hydraulic requirements.

Background

- Drilling with 17-1/2” BHA from 20” shoe down to 736m.
- DwC^{TM} initiated at 736m to a planned TD of 1372m with 13-3/8” 68 lb/ft L80 casing BTC connections.
- Torque Rings installed across unconsolidated sands and clay formations.
- Weatherford Heavy Duty (HD) Spira-Glider centralizers were made up to every 5th casing joint and kept in position by a stop collar on the lower side of the centralizer.
- Float collar was installed two joints behind the Weatherford casing drilling bit [Defyer DPA8516 (13-3/8” x 17”)].

Result

- Drilling ceased at 1172.95m after drilling 436.95m with an average ROP of 7.8m/hr.
- Losses were observed at approximately 1134m at 30bbl/hr.
- Hardened conglomerate (UCS 8,000-16,000psi) formation experienced at 1172m when drilling ceased.
- Casing has to be retrieved back to surface and RIH with conventional BHA.
- Large core samples were found inside the lower part of the casing and (casing drilling DPA series) bit when retrieved back to surface.
- Significant damage and scarring induced to the Casing drilling Defyer^{TM} DPA bit when retrieved with no cutting face intact. This is shown in *Figure 16.*
- All HD Spira-gliders were still intact and retrieved with the casing.
- All torque rings were installed with no issues and retrieved when connections backed out to lay down casing.

Job Failure investigation

- Initial wash out of nozzle at approximately 933m resulted in consistent bit balling through clay formations.
- Unable to clean bit due to 86.7% of flow through single nozzle.
- Continual hydraulic erosion through washed out nozzles due to maximum tolerance of 65ft/sec across aluminum prior to failure.
- Drilling became harder from 998m when additional nozzles were lost and aluminum crown washed away. This is supported through D-exponent decrease and slower ROP in clay due to being unable to clean and cool the bit.

- Drilling continued with minimal aluminum face remaining in sands and clay (UCS ≤4,000psi) until harder conglomerate (8,000psi – 16,000psi) formation experienced at 1172m sheared remaining face structure.

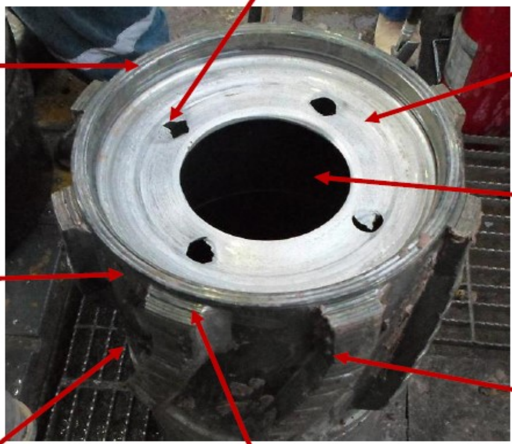

Figure 16: DPA bit after retrieval

- Prolonged drilling parameter variations (WOB, RPM, GPM) resulted in mechanically shearing the face and providing smooth finish (evident on bit retrieval).
- Conglomerate formation required increased HHSI which was unable to achieve due to nozzle washout.
- No aluminum structure in place to retain tensile strength of bit (up to 20,000psi) across conglomerate.
- Prolonged degradation of bit evident with multiple coring samples within casing on retrieval.

4.2.5 Lessons to Learn

a) Nozzle Selection

Change to Type 300 nozzles which can withstand prolonged higher flow rates through ceramic and copper retainer design.

Increase nozzle size to reduce jet velocity. It is better for:

- Prolong life of nozzle.
- Improve cleaning efficiency of bit.

b) Valve selection

Install poppet float valves. They are able to work at high flow rates for extended period of times. They are able to flow up to 1,000gpm for prolonged periods of time.

4.2.6 Hazard mitigation

Hazard identification and mitigation are some of the most important parameters which should be kept in mind while designing any operation. Overall hazard intensity of the operation has to be reduced to the acceptable level. *Table 3* is the hazard identification and risk analysis chart.

Table 3: Identified Hazards and Risks

Risk analysis for Casing Drilling		
Identified Risk	**Consequences**	**Mitigation Measures**
Loss circulation	Poor hole cleaning; Low ROP; Differential sticking; Mud loss	Monitor Returns; Reduce gpm; Add LCM materials
Low ROP	No or less advances in drilling	adjust parameters; sweep high-vis for hole cleaning
Nozzle plugging	Increase in SPP; Low ROP due to bit-balling	Use fine LCM material; Monitor returns on shaker
Bit failure	Low ROP; Drop in SPP; inability to drill ahead	Consider setting if near TD, otherwise retrieve back
Stuck pipe (Mechanical Sticking)	Increased T&D; Increased circulating pressure; Tight hole; Inability to move pipe	Increase Mud weight & flowrate
Deviation issues	Inability to maintain well trajectory	Lower WOB; Reduce RPM
Casing connection failure	Inability to drill ahead; Drop in SPP; Casing twist-off	POOH casing and do fishing (if required)
Well control situation	NPT; increased mud returns	Keep Mud wt. high; Close BOP

Buckling	High torque; Low ROP; Casing twist-Off	Ensure driller do not exceed recommended WOB
High Torque and Drag	High fatigue and cyclic stresses on tubulars	Add lubricating agent and ultra-free; no centralizer in open hole

4.2.7 Conclusion and Recommendations

Casing drilling is highly recommendable. It may not save money but it will save time and reduce contingency at-least. Following are some of the recommendations made.

- Always kick in the pumps and rotate before going to bottom.
- Increase the WOB gradually to achieve the desired ROP.
- Excessive WOB will reduce bit life.
- Do not rotate top drive at more than 100 rpm for prolonged duration.
- During circulation before connection reduce to 10RPM.
- Connection time was decreased as the drillers could gain viable experience during the casing run with the overdrive system.
- To drill out the float cement and drill shoe a used PDC should be used for future jobs.
- Do not ream as it may impair the drill shoe.
- Monitor pump pressure and torque carefully. An increase in pump pressure accompanied with reduced torque and ROP may indicate bit balling.
- Warning for using high viscosity sweeps. High viscosity sweeps will increase the ECD, which will increase the possibility of breaking down the formation.
- Reduce OD of casing drilling [Defyer DPA bit (if possible)] in clay type formations to reduce cutting volume in sticky type formations.

5.0 Offset well reference

5.1 Introduction

The offset well reference data is described here in this chapter. Miano-19 is the latest offset well and is also nearby the prognostic well which is named as "Miano-NN". Firstly offset well schematics and design is described. It is followed by the statistics of the well from different data sources.

5.2 Offset wells summary

Till to-date 19 wells have been drilled in the Miano field. OMV used two different well schematics from the day it started drilling in this field. Well number 1-18 are drilled with four (4) casing strings while the latest well is drilled with three (3) casing strings.

5.2.1 Offset wells (Four string casing schematics)

The casing string schematics with four strings are shown in *Figure 17*. The first casing known as conductor casing is just down to 60m and is intended to contain the loose sand. This casing is not drilled but it is hammered-in by a surface location preparation contractor.

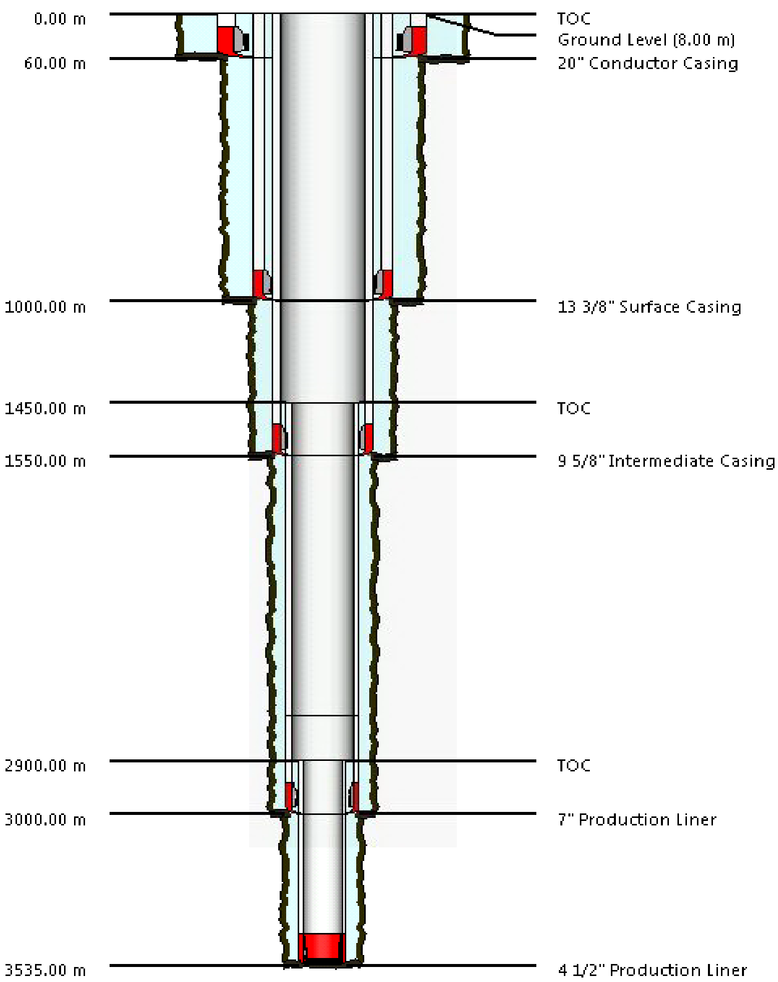

Figure 17: Offset well schematics (4- casing strings)

The surface casing (13-3/8” diameter) is down to 1000m and BOP is installed on it. Intermediate casing (9-5/8” diameter) is drilled down to 1550m to case-off two problematic zones i.e. Ghazij and Sui main limestone (SML). Then a 7” liner is drilled to 3000m in this case (in most of off-sets wells depth varies between 2400-3000m for this liner). The reservoir section is drilled with 6” hole and cased-off with 4-1/2” liner at total depth.

5.2.2 Offset wells (Three string casing schematics)

Just recently company drilled a well with three string casing schematics. This is shown in

Figure 18. In this casing schematics, conductor casing is hammered in. 13-3/8” diameter surface casing is run down to 1000m. 9-5/8” diameter intermediate casing is run down to 2300m. The third string is 7” liner string down to 3550m.

The problematic zones i.e. Ghazij and SML in this section are handled by reduced parameters and use of some new loss circulation materials (LCMs). ROP, RPM and pump flow rate is reduced. Some quantity of LCM is already put into active mud system. Still in case of loss circulation, spot pills are used. Also, frac-seal™ and stop-loss™ materials are used which ensure effective filter cake on the walls of the wellbore.

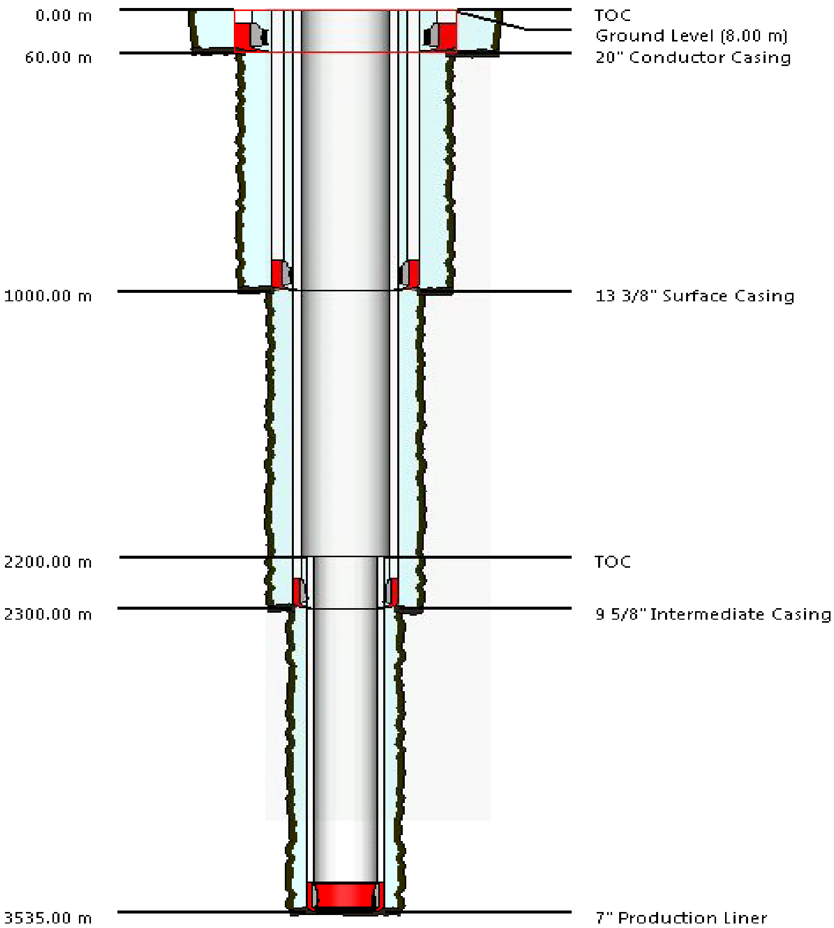

Figure 18: Offset well schematics (3-casing strings)

5.2.3 Drilling with casing plan

Drilling with casing was planned in 9-5/8” 47ppf casing for 400m of section in 12-1/4” hole. The plan was to drill with casing from 1900-2300m. The plan was partially dismissed due to partner company concerns. It was then decided to run the casing using Weatherford casing running overdrive tool and a reamer shoe. Every joint was filled upon RIH. When the casing reached 1796m, casing holdup of 10ton was observed. It was tried to clear the obstruction with circulation but of no use. String stalling and pack-off of annulus was observed.

It was then decided to ream the casing, circulation was continued bottom up. Big amount of caving’s were observed on shakers. Casing was then washed and reamed down to 1921m (planned casing shoe depth). Maximum anticipated values for torque were observed to be 11.39 kft-lb with mode value of torque around 6 kft-lb. Maximum and mode value for flow rate was 400gpm. Maximum pump pressure was observed to be at 740 psi. The real time data extracted from Kongsberg is given in ***Appendix D*** *Figure 78*.

During drilling of the same section from 1796-1925m, maximum torque value was observed to be 8.8kft-lb at 750 gpm and 2100psi pump pressure. The real time data extracted from Kongsberg is given in ***Appendix D*** *Figure 79*.

5.2.4 Performance Analysis

This software evaluates the real time status of the rig and provides performance charts. This software is capable of recognizing different states of the rig including drilling, tripping, reaming etc. In this way a standardized and objective categorization of the drilling process can be achieved.

a) Time vs Depth graph

The time vs depth curve for the well is shown below in *Figure 19*. Blue line shows actual well depth and green line shows bit depth. This graph shows two casing setting depths and one liner setting depth. Other operations in this graph are coring and logging. The last flat section has completions, slick line, wire line and Coil tubing runs. The half-way runs in the last flat section show the dummy runs before running in hole the expensive equipment.

The same T vs D graph is made for the prognosis wells in *Chapter 356.0* by the use of excel file.

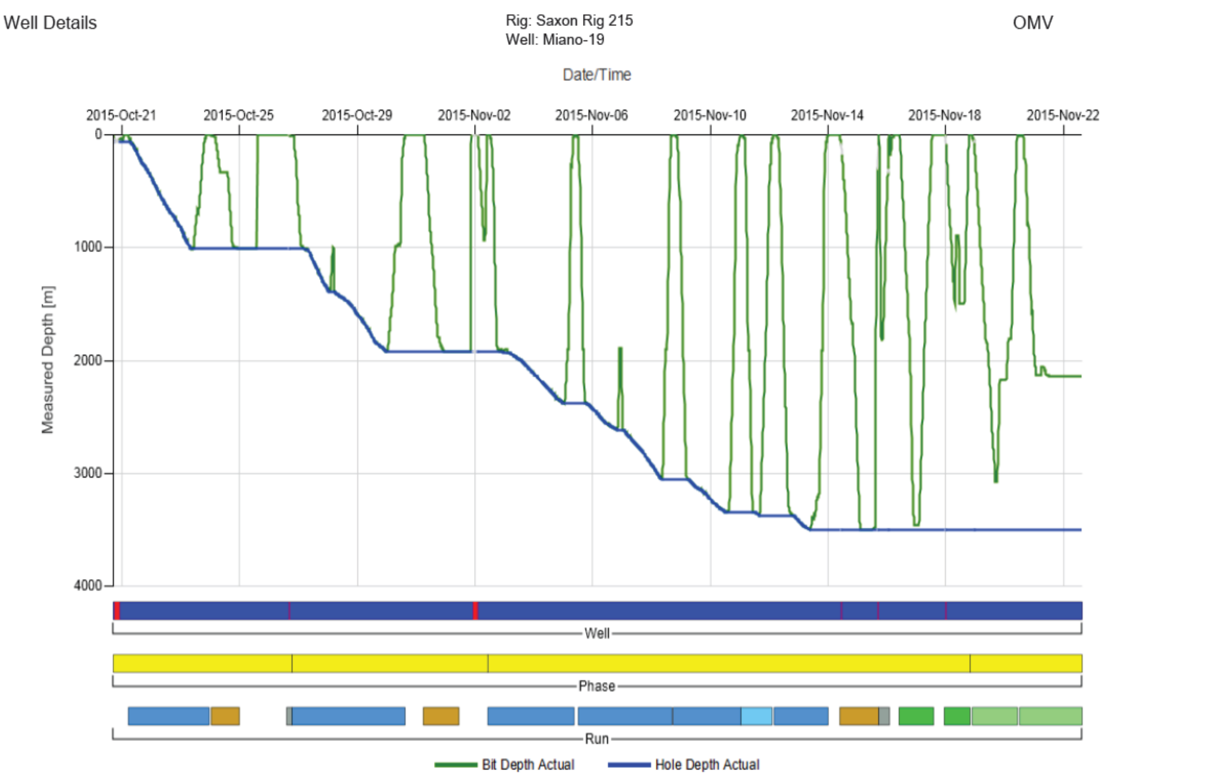

Figure 19: Time vs drilled depth and bit depth (Miano-19)

b) Time break down section

Actual time break down is shown below in *Figure 20.* This actual time is taken into consideration for planning the next well Miano NN.

Color	Operation	hh:mm	[%]
	Drilling rotating	209:58	26.57
	Drilling sliding	00:00	0.00
	Ream upwards (backreaming)	27:07	3.43
	Ream downwards (into hole)	25:53	3.27
	Wash upwards (out of hole)	07:51	0.99
	Wash downwards (into hole)	04:56	0.62
	Run in hole	35:59	4.55
	Pull out of hole	30:00	3.80
	Circulate hole	46:50	5.93
	Make connection	178:34	22.60
	Other operation	223:06	28.23
	Sum	**790:15**	**100.00%**

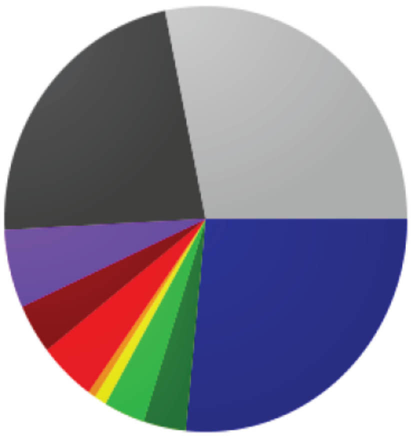

Figure 20: Time breakdown (Miano 19)

Break down of the total time as drilling time, flat time and invisible lost time is shown below in *Table 4.* Invisible lost time is due to slow operations. While flat time includes productive time and non-productive time which needs to be segregated.

Table 4: Drilling time and Flat time distribution (Miano-19)

Well #	Bit on bottom time		Flat time		Invisible lost time		Total Days
	Days	%	Days	%	Days	%	
Miano-19	8.7	26.6	24.2	73.4	1.4	4.3	32.9

Time break down of all the non-productive time from Independent Data Services (IDS) software is shown in *Figure 21*. The total NPT according to IDS is 135.7 hours (5.65 days) which is 17% of the total time.

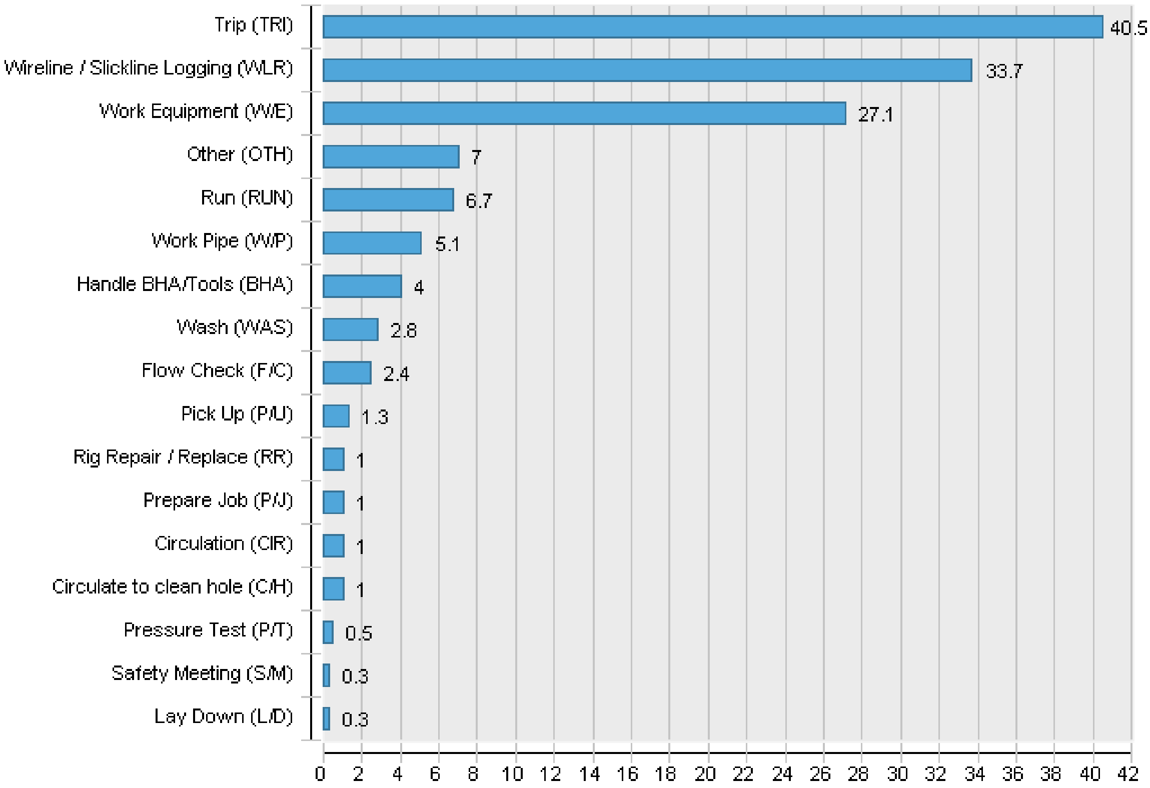

Figure 21: Time breakdown chart of NPT (Miano-19)

c) Tripping operations

Tripping operations of the complete well are shown below in *Figure 22.* Casing statistics are shown in *Figure 23.*

Tripping and casing running time for prognosis well is designed keeping in view the tripping statistics shown below and discussion with drilling superintendent.

TxD KPI Operation Report — Rig: Saxon Rig 215 Asia/Karachi — Well: Miano-19 2015-Oct-20 17:00 - 2015-Nov-22 15:15 — OMV

Tripping Statistics		
Rig	**Saxon Rig 215**	
Well	**Miano-19**	
Shift Type	**Day Shift**	**Total**
Crew	Saxon Rig 215 Crew	-
Total Time Trip In [hh:mm]	28:12	28:12
Total Time Trip Out [hh:mm]	27:42	27:42
Total Depth Trip In	16315 m	16315 m
Total Depth Trip Out	15805 m	15805 m
Gross Running Speed Trip In	579 m/h	579 m/h
Gross Running Speed Trip Out	572 m/h	572 m/h
Avg Pipe Moving Speed Trip In	1356 m/h	1356 m/h
Avg Pipe Moving Speed Trip Out	1171 m/h	1171 m/h
Count of Slip to Slip Connections Trip In	569	569
Count of Slip to Slip Connections Trip Out	549	549
Avg Pipe Moving Time Trip In [min]	1.25	1.25
Avg Pipe Moving Time Trip Out [min]	1.43	1.43
Avg Slip to Slip Connection Time Trip In [min]	1.57	1.57
Avg Slip to Slip Connection Time Trip Out [min]	1.61	1.61

Figure 22: Tripping statistics (Miano-19)

TxD KPI Operation Report — Rig: Saxon Rig 215 — Well: Miano-19 — Asia/Karachi — 2015-Oct-20 17:00 - 2015-Nov-22 15:15 — OMV

Casing Statistics		
Rig	**Saxon Rig 215**	
Well	**Miano-19**	
Shift Type	**Day Shift**	**Total**
Crew	Saxon Rig 215 Crew	-
Total Csg Running Depth	3812 m	3812 m
Total Csg Running Time [hh:mm]	21:53	21:53
Count of Csg Joint Connections	332	332
Csg Gross Running Speed	174 m/h	174 m/h
Avg Joint Running Speed	578 m/h	578 m/h
Avg Joint Running In Time [min]	1.26	1.26
Avg Joint In Slips Time [min]	2.98	2.98

Figure 23: Casing statistics (Miano-19)

From the well comparison module of proNova^{TM} software, chart showing the average time of different drilling operations are generated. The slip to slip connection time and saving potential report of the well is attached in ***Appendix E***.

Net ROP of the different phases of well along with total circulation time, reaming time and washing time per stand are shown in the *Figure 24*. The average values used for planning of prognostic well are also in conjunction with the data from this offset well.

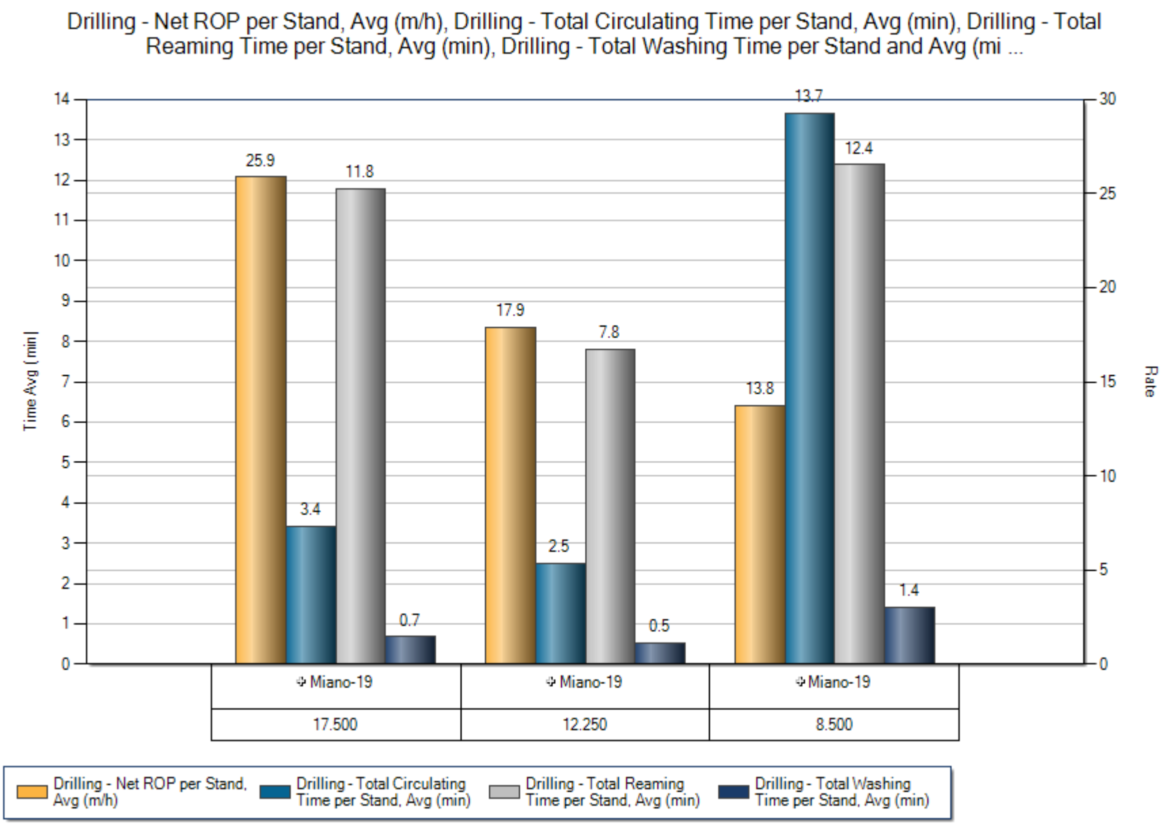

Figure 24: Well comparison statistics (Miano-19)

6.0 CASE STUDY

6.1 Prognosis well design

Keeping in view the latest well drilled. It was decided to keep the three string casing design. Selection of casing shoe was a problem. After detailed discussion with the geologists and looking through the D- exponents of offset wells. It was found that the likelihood of getting over pressured gas zones in the depth from 0-1500m is very unlikely. So, requirement for BOP is not necessarily there. So, it was principally decided to deepen down the casing shoe to 1500m for surface casing and then install BOP on it. The intermediate shoe can be placed anywhere from 2400-3000m in lower guru shale unit, while the last section is drilled to total depth.

For the purpose of designing a well, three (3) scenarios are made for a single wellbore design. All three of them are checked and approved by the drilling department with respect to technical and economic design considerations. OMV practices and drilling engineering manual along with offset wells were used to make the best possible design.

Three scenarios are made to evaluate the feasibility of casing and liner drilling in the OMV Pakistan operations. Complete and detailed technical and commercial analysis is done to analyze the applicability of this new emerging technology. All the three cases show **vertical wells**. Cases are described below:

- Case 1A is the Conventional case: All the well sections are drilled conventionally
- Case 1B is the Casing Drilling (CD) case: Casing drilling is partially done in two casing sections
- Case 2 is the Slim bore case: Casing Drilling and Liner Drilling (LD) is done in two separate sections

All these cases are generated for the comparison purpose and applicability of this technology in the Miano field keeping in view the company past practices and available offset well data. Landmark software modules are used to make the technical models and commercial analysis is done on Microsoft Excel. Wellbore schematics are made using compass software and company past practices of drilling only vertical wells in conventional reservoirs. Vertical wells

Planned Survey

Measured Depth (m)	Inclination (°)	Azimuth (°)	Vertical Depth (m)	+N/-S (m)	+E/-W (m)	Map Northing (m)	Map Easting (m)	Latitude	Longitude
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15° 22' 45.173 N	42° 40' 44.901 E
3,550.00	0.00	0.00	3,550.00	0.00	0.00	0.00	0.00	15° 22' 45.173 N	42° 40' 44.901 E

Figure 25: Planned survey (All Cases)

are drilled due to presence of compartments in the field. Casing design is based on company practices and availability of tubular/casing inventory. Torque and drag designs are made to show the best optimal solution for all the cases. Hydraulics section focuses on the concept of cuttings transport and good hole cleaning requirements along with maintaining ECD for proper well control while saving it from fracturing the formation.
Parameters used in the modelling of these cases are kept the same. The casing shoe depths selection and hole schematics are different in conventional and slim bore case.
The well schematics are kept simply vertical as shown in *Figure 25.* It is same for all the three cases. Map system used is “Kalianpur 1962”. System datum is Mean sea level with a TVD reference of 44m and a rotary height of 8m as shown in *Figure 26.*

Database:	EDM5000RegionalPK_USER	**Local Co-ordinate Reference:**	Site Miano NN Test well 1
Company:	OMV Pakistan External	**TVD Reference:**	WELL @ 52.00m (Original Well Elev)
Project:	OMV Pakistan CWD	**MD Reference:**	WELL @ 52.00m (Original Well Elev)
Site:	Miano NN Test well 1	**North Reference:**	Grid
Well:	well design 1	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	Wellbore #1		
Design:	conventional design		

Project	OMV Pakistan CWD, Miano NN, Case Study		
Map System:	Kalianpur 1962	**System Datum:**	Mean Sea Level
Geo Datum:	Kalianpur 1962		
Map Zone:	OMV Zone		

Figure 26: Co-ordinate reference (All Cases)

Miano field has two main problematic zones:

- Ghazij formation: these are unstable clays which causes the caving-ins
- Sui main limestone(SML): fractured limestone causing lot of mud losses

Both these formations are present just adjacent to each other. Ghazij is shallower and SML is just below it. Increasing the mud weight while drilling causes the Ghazij formation to stabilize but as soon as we enter the SML, losses start to occur (which are sometime very hard to contain even with loss control materials). Setting a casing just below Ghazij is possible but it do not help as we still have to drill the next section and even if losses are cured with LCMs still we are not able to drill far deep with SML section open to well bore. In this case we will have a weak casing shoe so this is not possible to execute. The only possible solution is to case off these two sections in one-go behind the single casing.

The formation schematics are shown in *Figure 27* and remain the same for all the cases. The formation tops are given and correspond to MD/TVD.

Formations					
Measured Depth (m)	Vertical Depth (m)	Name	Lithology	Dip (°)	Dip Direction (°)
8.00	8.00	Ground			
410.00	410.00	Formation 2	Limestone, Dolomitic	0.00	
511.00	511.00	Formation 4	Marl	0.00	
610.00	610.00	Formation 5	Limestone, Dolomitic	0.00	
681.00	681.00	Formation 6	Clay	0.00	
812.00	812.00	Formation 7	Limestone, Dolomitic	0.00	
1,415.00	1,415.00	Formation 8	Clay	0.00	
1,503.00	1,503.00	Formation 9	Limestone, Dolomitic	0.00	
1,855.00	1,855.00	Formation 10	Siltstone	0.00	
1,907.00	1,907.00	Formation 11	Limestone, Dolomitic	0.00	
2,262.00	2,262.00	Formation 12	Marl	0.00	
3,064.00	3,064.00	Formation 13	Shale	0.00	
3,157.00	3,157.00	Formation 14	Sandstone, Fine	0.00	
3,550.00	3,550.00	Formation 15	Siltstone	0.00	

Figure 27: Formation tops of Miano field

6.1.1 Prognostic wells Summary

Casing setting depths of all the three cases is given in Table *1Table 5*. Conventional case and casing drilling case have same casing shoe depths and all casing diameters are also the same. The slim-bore case has slightly different casing setting depths. The casing diameters are also different in slim-bore case. Technically it is feasible to use 4-1/2” liner because final completions are 3-1/2”. The only problem can be that we do not have any contingency liner in slim-bore case. As, we now have lot of experience, drilling in this field so no un-planned events are expected. So, it is acceptable to reduce the cost and drill the well faster.

Table 5: Casing shoe depth (All cases)

Casing/ Liner	Conventional case		Casing drilling case		Slim-bore case	
	Diameter	Shoe depth (m)	Diameter	Shoe depth (m)	Diameter	Shoe depth (m)
Conductor	20"	60	20"	60	13-3/8"	60
Surface	13-3/8"	1500	13-3/8"	1500	9-5/8"	1500
Intermediate	9-5/8"	2800	9-5/8"	2800	7"	2600
Production	7"	3550	7"	3550	4-1/2"	3550

6.1.2 Fracture and pore pressure

Fracture and pore pressure of the formations are known. They vary in some of the wells but generally they remain the same. The geothermal gradient of the formations is shown in *Figure 28*. Mud weight used in the offset well data is also shown here on pore and fracture pressure cumulative graph. These mud weights remain the same for our prospective well. All the graphs in *Figure 28* show the actual field data from offset wells. Fracture gradients are taken from LOT data available from offset wells.

The concept of employing CD and LD is not only to save time and cost, but the major consideration factor is to reduce uncertainty in drilling these formations [12].

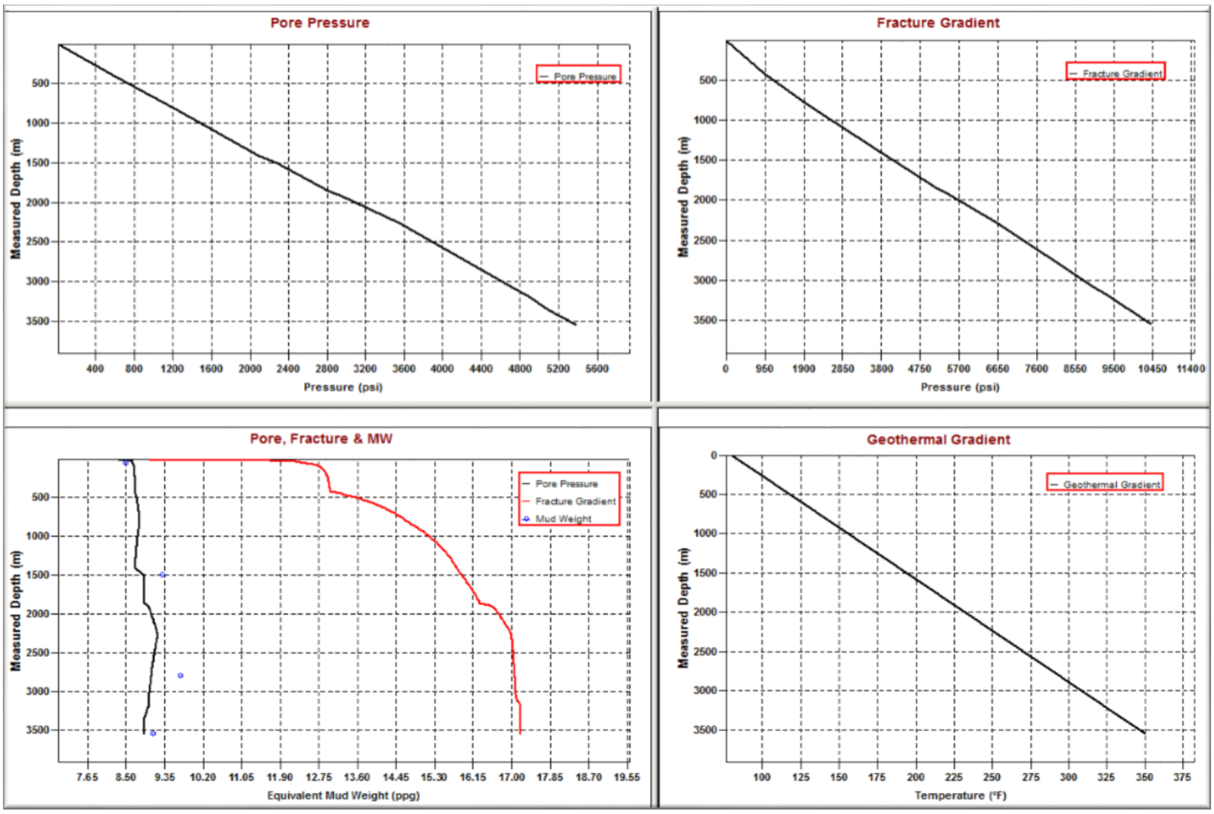

Figure 28: Formation properties of Miano field (All cases)

Following Safety Factors are used for stress analysis in all the cases. This is shown in *Table 6* below. These safety factors are in line with OMV “Drilling Engineering Standards Manual” and “Well Engineering Technical Policy” chapter 5.3 [13].

Table 6: Stress analysis safety factors (All cases)

Parameters	S.F	Parameters	S.F
Burst	1.1	Compression	1.5
Collapse	1.1	Tension	1.5
Tri-aixal	1.25		

The detailed analysis of each individual case and then their comparison is given in next sections. The prognostic well going to be drilled is named as “**Miano NN**” well.

6.2 General Properties: Case-1A and Case-1B

Conventional case (case-1A) and CD case(case-1B) are similar. Only difference is that in CD case casing drilling is tried on two casing sections. Both these cases have a three string casing design. Structural (conductor) casing is 20” diameter and only goes down to 60m. Surface casing is at the depth of 1500m. Intermediate casing is down to 2800m. The production Liner is down to 3550m approximately as shown in *Figure 29*.

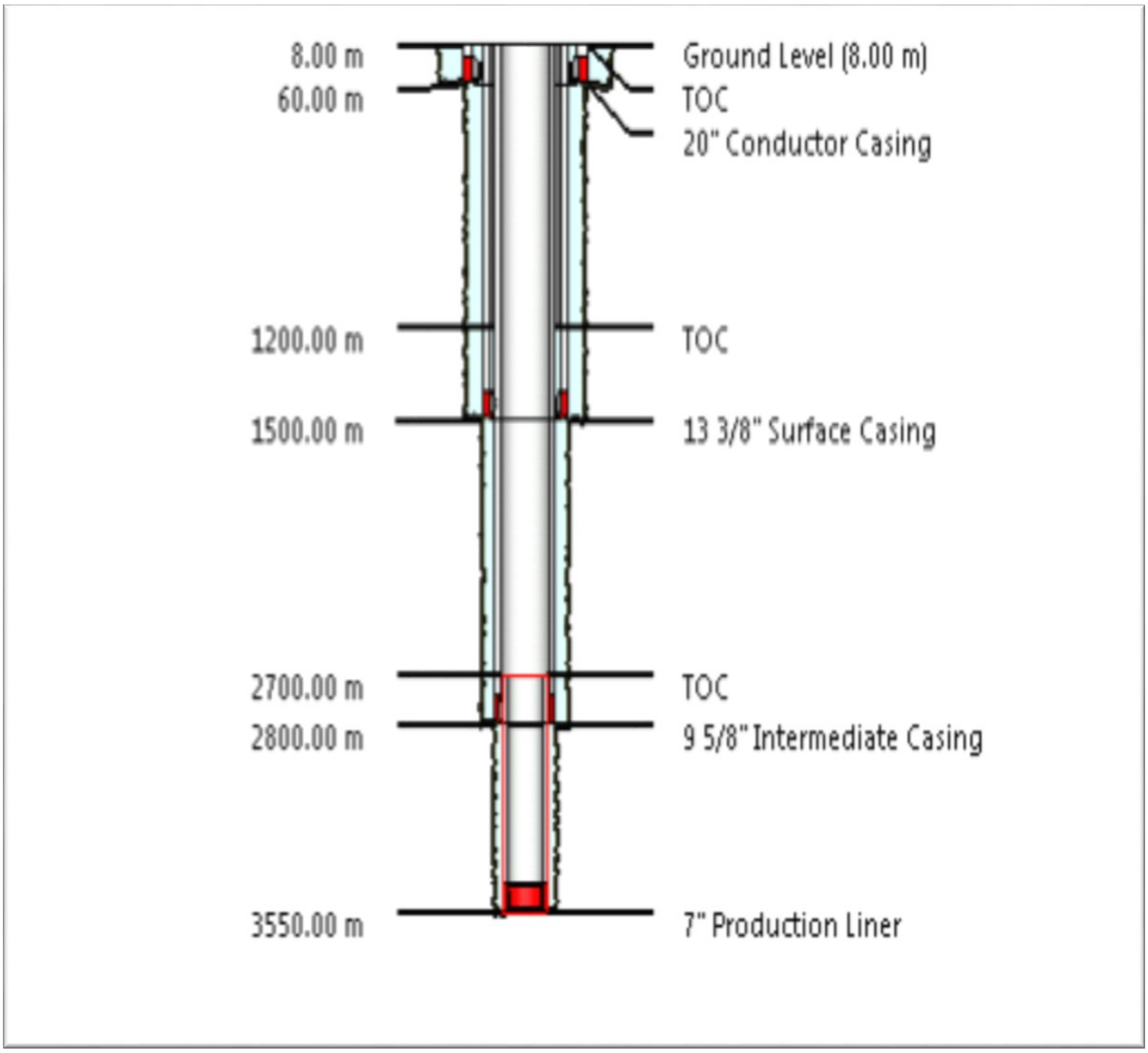

Figure 29: Well schematics (Conventional and CD case)

6.2.1 Compass design: Case-1A and Case-1B

First casing is set just at the shoe of SML formation. Snapshot of schematics from Compass is shown in *Figure 30.* It shows the casing setting depths and the formation tops.

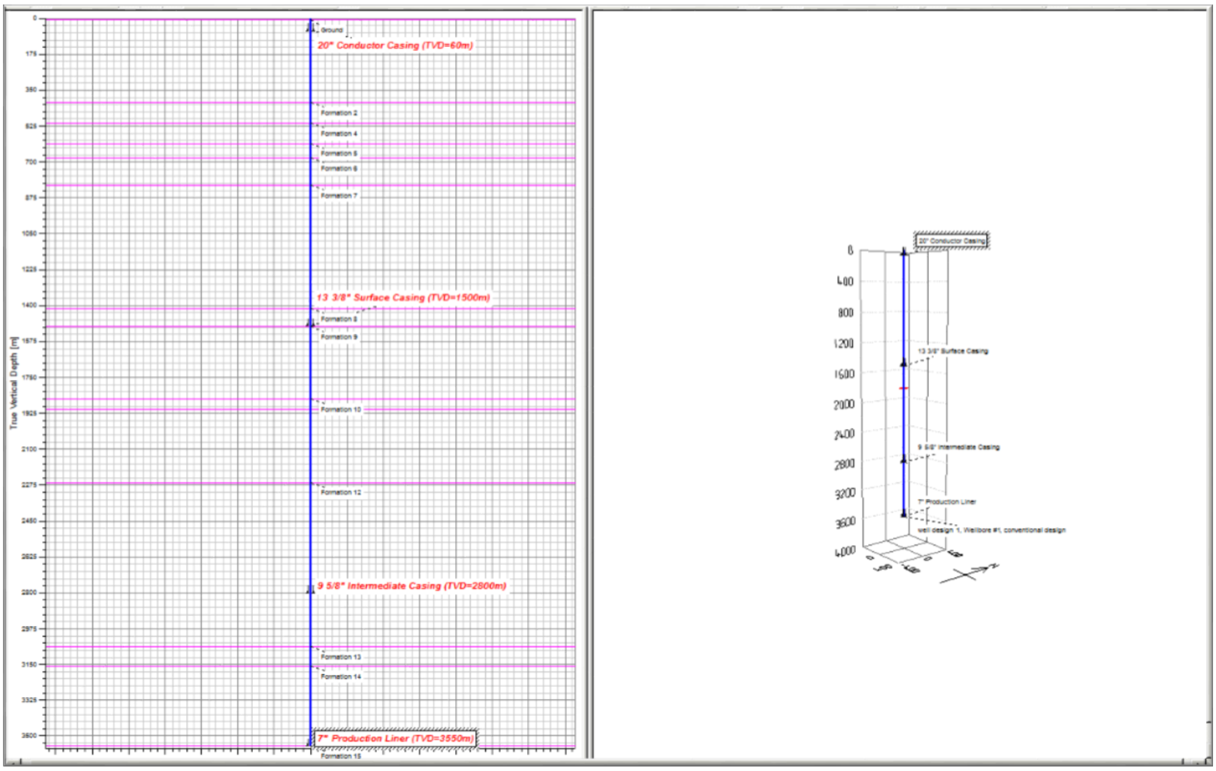

Figure 30: Section view (Conventional and CD case)

6.2.2 Stress-Check design: Case-1A and Case-1B

Casing tubular design is considered keeping in view the entire contingency factors available in stress-check. Casing selection is done on basis of availability of the casing strings in the inventory of the company. The well schematics and well summary for casing is given in *Figure 31.*

Casing and Tubing Scheme

	OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)			Mud at Shoe (ppg)
					Hanger	Shoe	TOC	
1	20"	Conductor	Casing	26.000	8.00	60.00	8.00	8.33
2	13 3/8"	Surface	Casing	17.500	8.00	1500.00	8.00	9.30
3	9 5/8"	Intermediate	Casing	12.250	8.00	2800.00	1200.00	9.70
4	7"	Production	Liner	8.500	2700.00	3550.00	2700.00	9.20
5								

Figure 31: Well Summary (Conventional and CD case)

6.2.3 Well plan: Case-1A and Case-1B

In the well plan module hydraulics and torque & drag is used to evaluate the optimum conditions for our drilling operations.

a) Hydraulics

Hydraulics is one of the key things for our effective drilling campaign. Good design is necessary for acceptable hole cleaning while keeping the physical constraints in mind.

b) Torque & Drag

During drilling the pipes/tubulars are exposed to greater amounts of torque and drag (T&D). If the torque and drag are not evaluated, it can result in stuck pipe, pipe failures, and costly fishing jobs. Now a days torque and drag modeling has become an essential process during the planning phase of drilling and casing running.

6.3 Case 1A (Conventional Case)

6.3.1 Stress Check: Conventional case

Stress check analysis of all the three string cases is described below.

a) Surface Casing (13-3/8” casing shoe @ 1500m depth)

This casing is run down to 1500m and BOP is installed onto it. So, it has to be cased and cemented properly. The burst, collapse, tri-axial and axial graphs show designed pressure lines which are all less than the pipe rating. So, all the cases show correct casing design as shown in *Figure 32.*

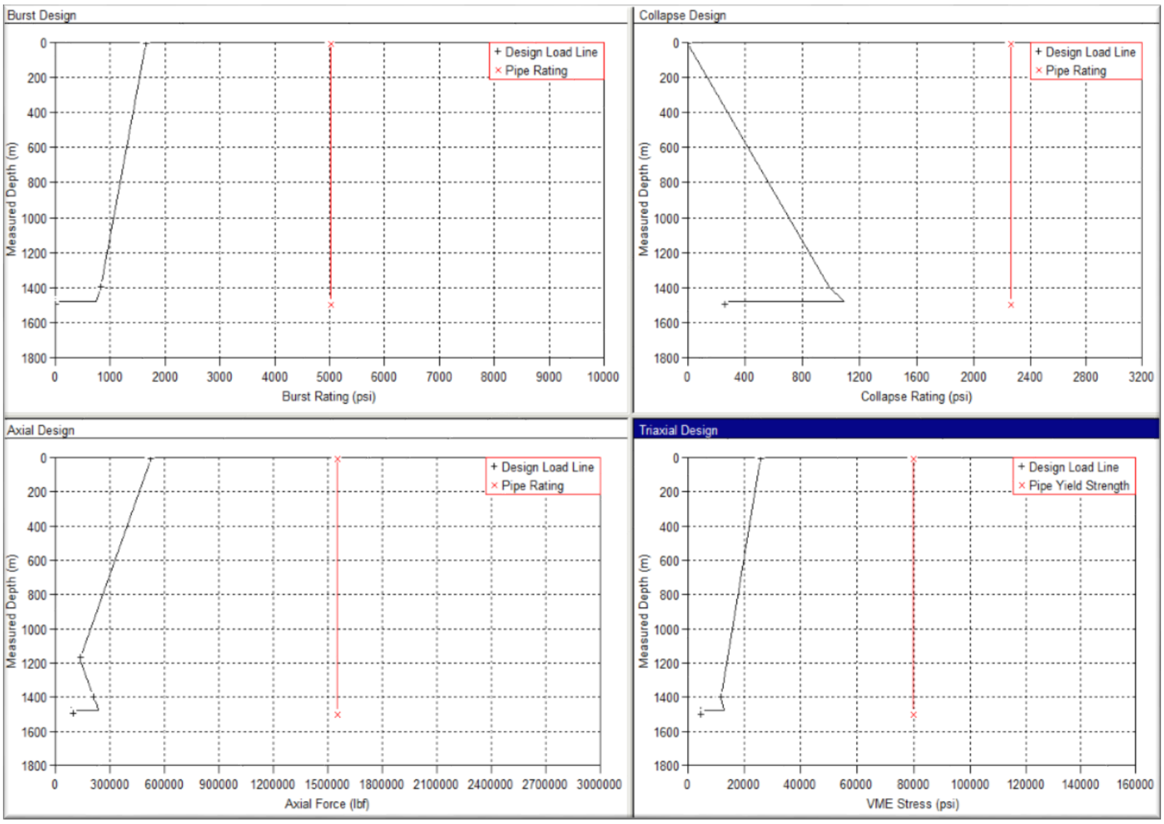

Figure 32: 13-3/8” Casing Design plots and Load ratings (Conventional case)

b) Surface Casing: 13-3/8” casing Von Mises Equation (VME)

VME of the casing also shows positive result. This is analyzed for axial and burst pressures of green cement pressure test, pre and post cement static loads, RIH, over pull and cementing cases. This is as shown in *Figure 33*.

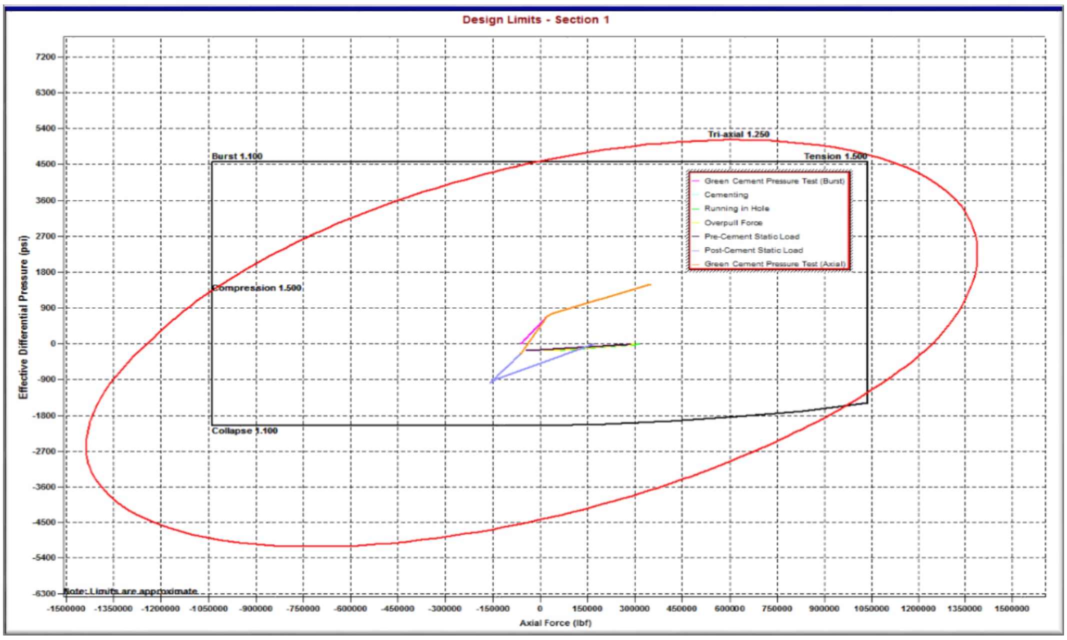

Figure 33: 13-3/8” Casing VME (Conventional case)

c) Intermediate Casing (9-5/8” casing shoe @ 2800m depth)

Stress analysis for 9-5/8” casing is shown. This casing is run down to 2800m. Top of cement (TOC) for this casing is 1200m (which is 300m into the next casing). The burst, collapse, tri-axial and axial graphs show designed pressure lines which are all less than the pipe rating. So, all the cases in *Figure 34* show correct casing design.

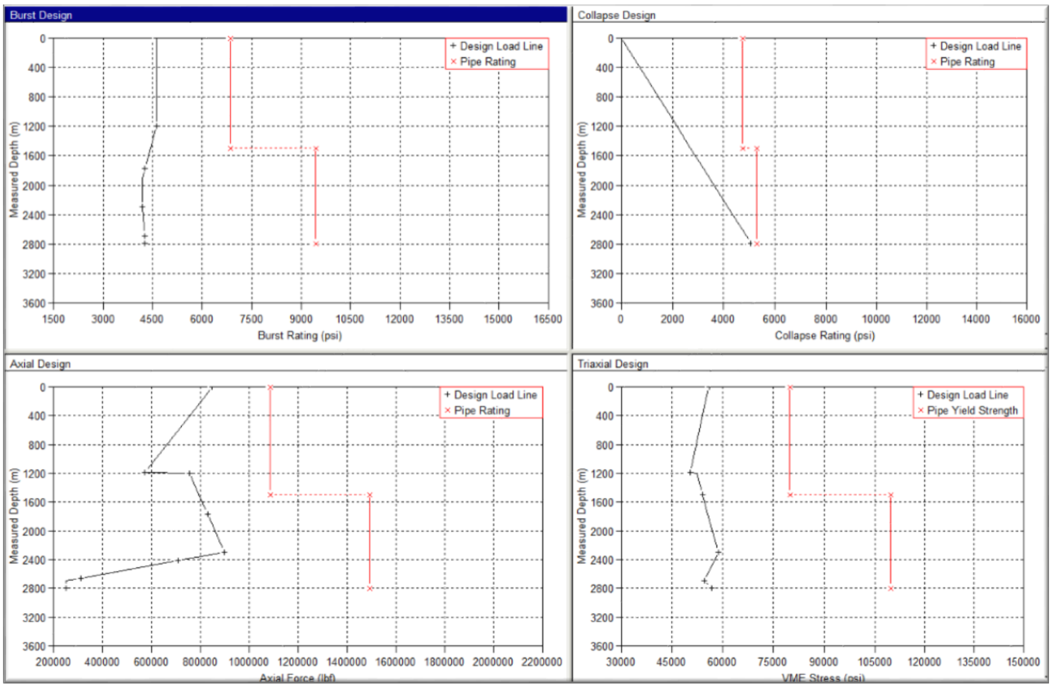

Figure 34: 9-5/8” Casing Design plots and load ratings (Conventional case)

d) Intermediate Casing: 9-5/8" casing VME

VME of the casing also shows positive result. This is analyzed for axial and burst pressures of green cement pressure test, pre and post cement static loads, RIH, over pull, gas kick tolerance for 50bbls, displacement to gas, burst due to drill ahead and lost returns. The VME for intermediate casing is shown in *Figure 35.*

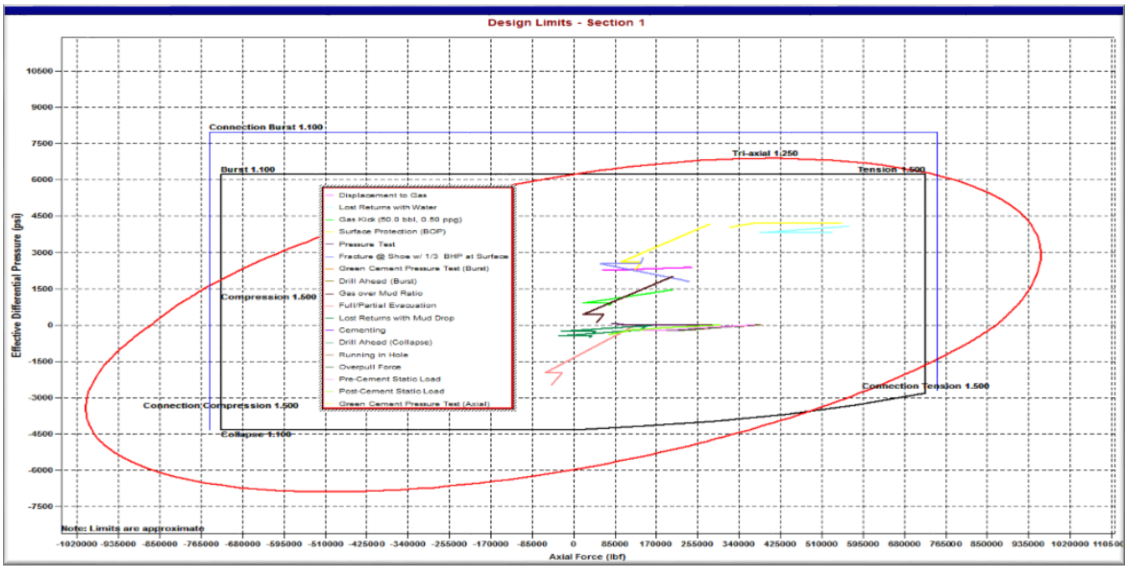

Figure 35: 9-5/8" Casing VME (Conventional case)

e) Production Liner (7" liner shoe @ 3550m depth)

Stress analysis for 7" casing is shown. This liner is run down to 3550m. TOC for this liner is 2700m (which is 100m into the next casing). The burst, collapse, tri-axial and axial graphs show designed pressure lines which are all less than the pipe rating. So, all the cases show correct casing design as shown in *Figure 36.*

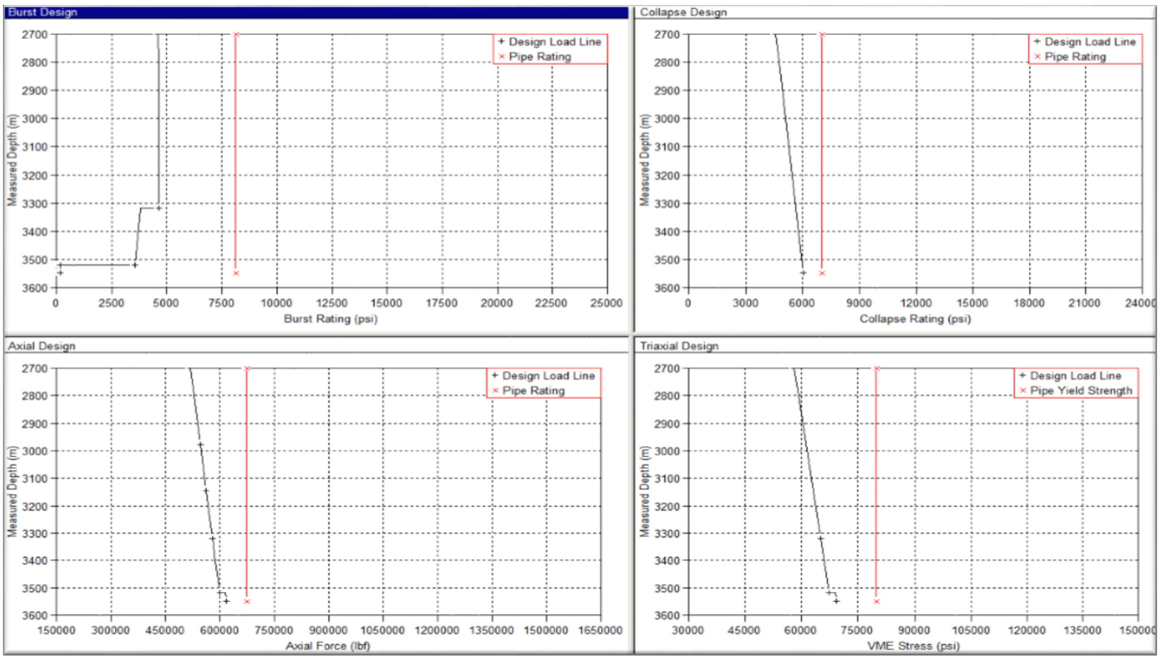

Figure 36: 7" Liner Design plots and load ratings (Conventional case)

f) Production Liner: 7” liner VME

VME of the casing also shows positive result. This is analyzed for axial and burst pressures of green cement pressure test, pre and post cement static loads, RIH, over pull, tubing leak, injection down casing, full evacuation and stimulation loads. This is shown in *Figure 37.*

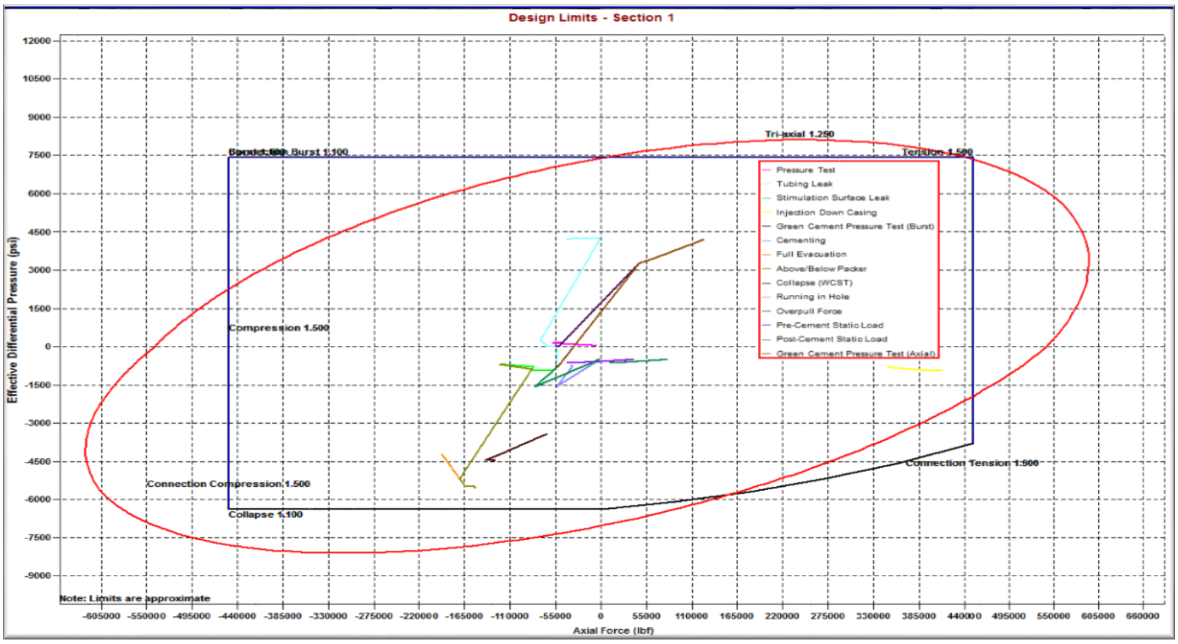

Figure 37: 7” Liner VME (Conventional case)

6.3.2 Well Plan: Conventional case

Hydraulics of each individual wellbore section is shown here. Torque and drag analysis is done to see load summary on our tubular string while drilling and running in hole of each individual section.

a) Surface hole (Hydraulics: 17-1/2” hole@ 1500m)

For this hole section minimum required flow rate is 750gpm @100rpm and ROP of 25m/hr. This ROP is from the offset wells. This is the international association of drilling contractors (IADC) ROP which is achievable in this section. RPM are also in conjunction to normal drilling practices. The assigned flow rate is 800gpm considering a certain level of working contingency and constraints.

Hydraulic cutting transport operational parameters graph shows inclination of the well, minimum flow rate, suspended & total volume and bed height generation w.r.t distance along string. This is shown below in *Figure 39.*

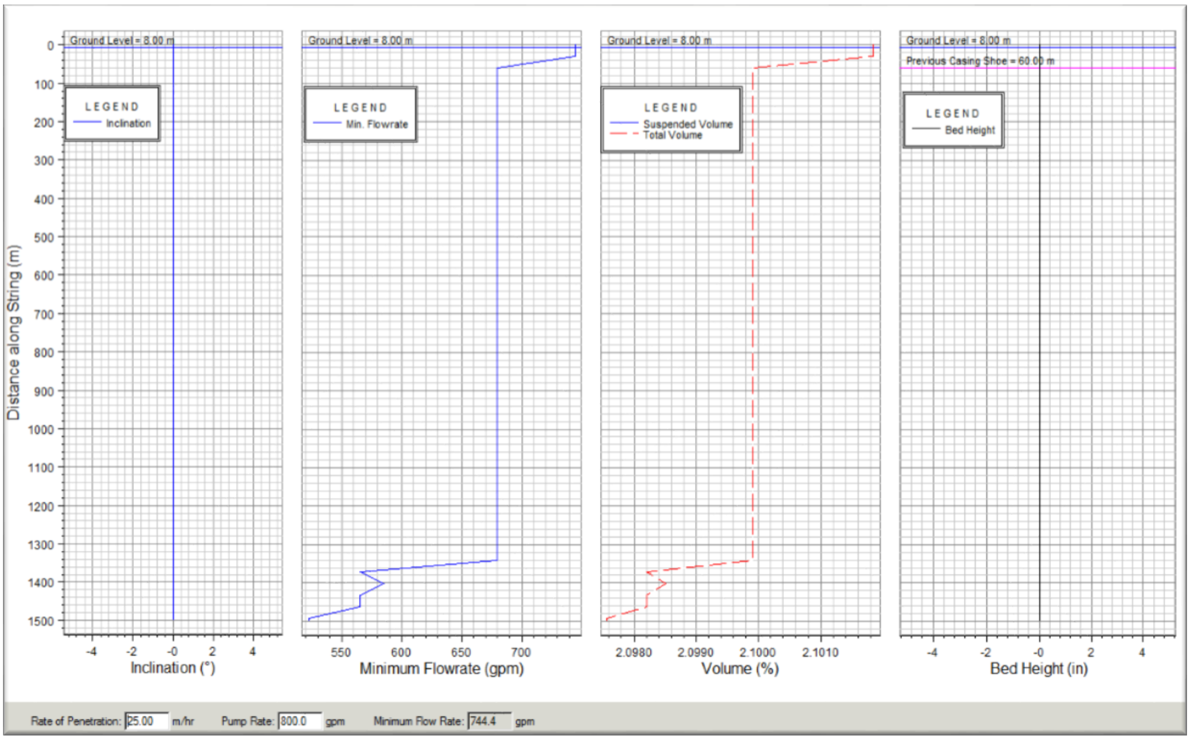

Figure 39: 17-1/2” Hydraulic transport parameters (Conventional case)

Circulating pressure and ECD vs depth shows one of the most important aspects of well control and effective hole cleaning. Pore pressure line is shown by dotted green line, dotted red line shows fracture pressure and black line shows ECD in both the graphs. Fracture pressure and pore pressure is from offset wells and is shown in *Figure 28*. Blue line on the right side graph shows pressure in the string and the red horizontal line in the bottom shows

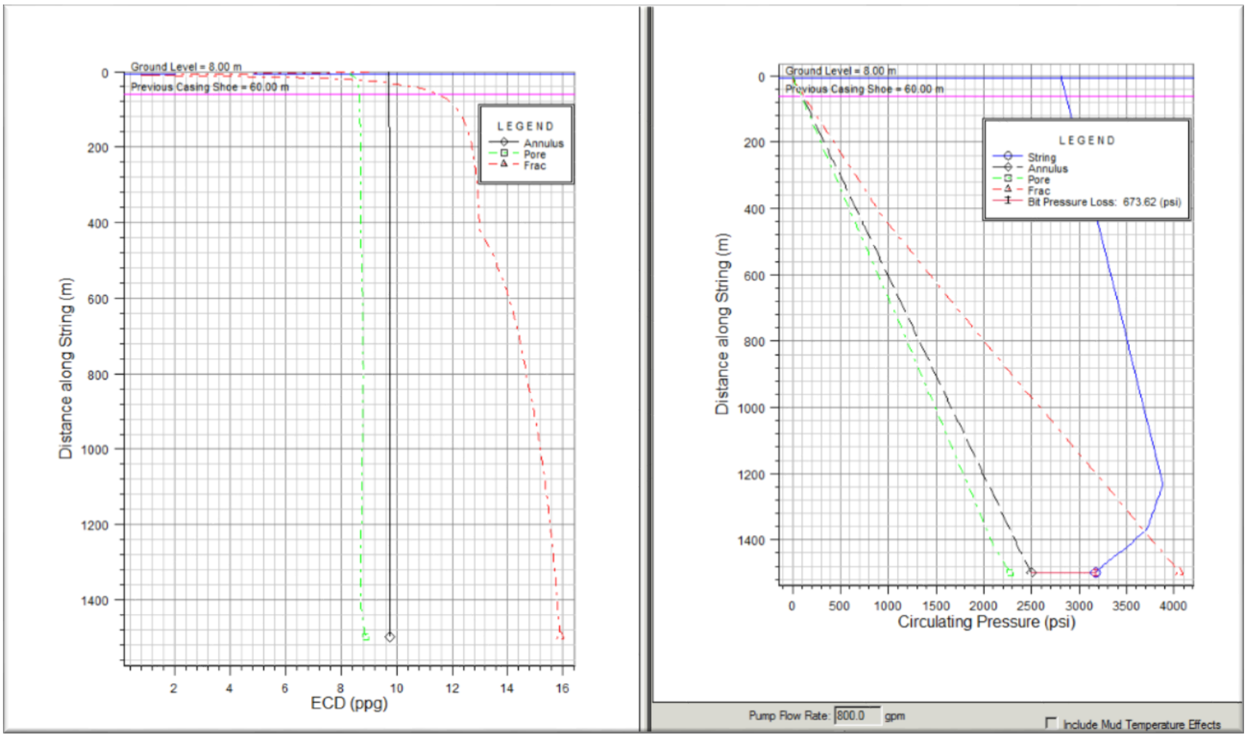

Figure 38: 17-1/2” ECD and Circulating Pressure vs Depth (Conventional case)

pressure loss across the bit. This is shown in *Figure 38.*

b) Surface hole (Torque & Drag: 17-1/2” hole@ 1500m)

This is a vertical well, so torque & drag is not of much importance. But company has a practice of making torque and drag model. The well is drilled with conventional BHA. Torque and hook load graph is shown with respect to depth. In the graph on the left, the torque limit of the top drive and make-up torque limits of tubular are shown in red lines. The other lines show rotating on bottom, rotating off-bottom, tripping-in, tripping-out and back reaming. From right to the left, rotating on bottom requires high torque followed by back reaming, RIH while rotating and POOH while rotating at low rpm.

In *Figure 40*, in the graph on the right, hook loads w.r.t rig capacity are shown. While moving from left to right, helical buckling during tripping-in is shown; highest hook load is shown while tripping-in. It should be noted that this graph is run measured depth, which means that top 200m section shows RIH of BHA. We make and Run in the BHA first and then drill pipe.

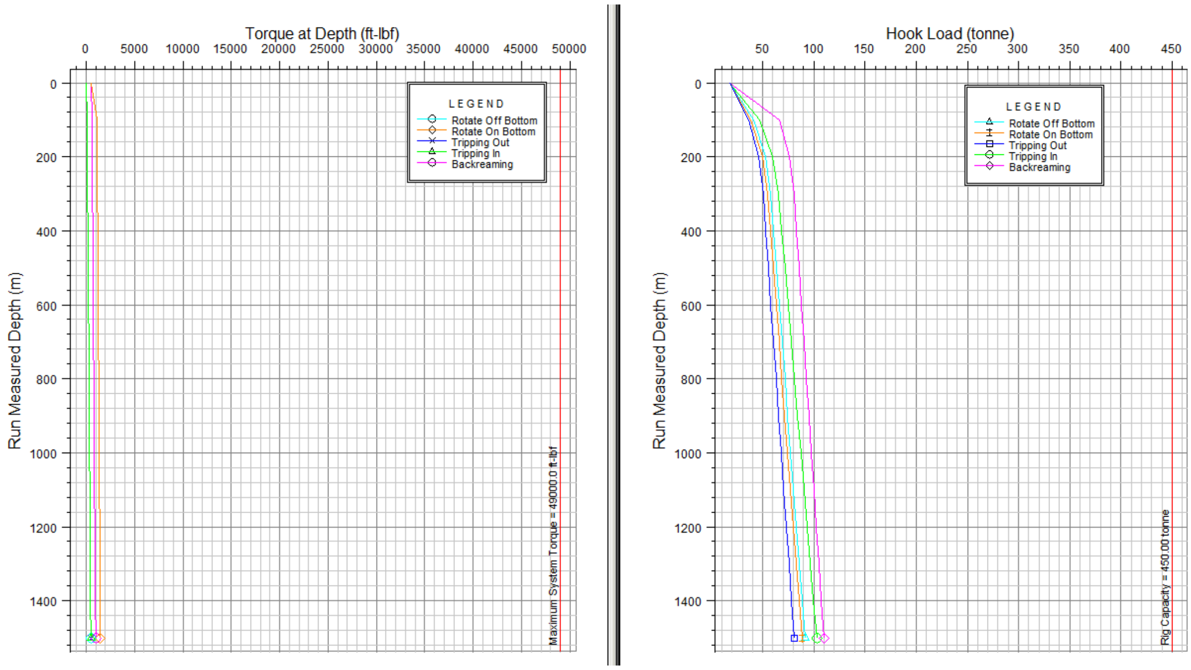

Figure 40: 17-1/2” Torque and Hook load with run Measured depth

c) Intermediate hole (Hydraulics: 12-1/4” hole@ 2800m)

For this section minimum required flow rate is 400gpm @100rpm and ROP of 17m/hr. The assigned flow rate is 500gpm considering a certain level of working contingency and company past practices. This is the maximum achievable ROP in this section.

Hydraulic cutting transport operational parameters graph shows inclination of the well, minimum flow rate, suspended & total volume and bed height generation w.r.t distance along string. The volume requirements increase in the section where there is previous casing shoe. This is shown in *Figure 41.*

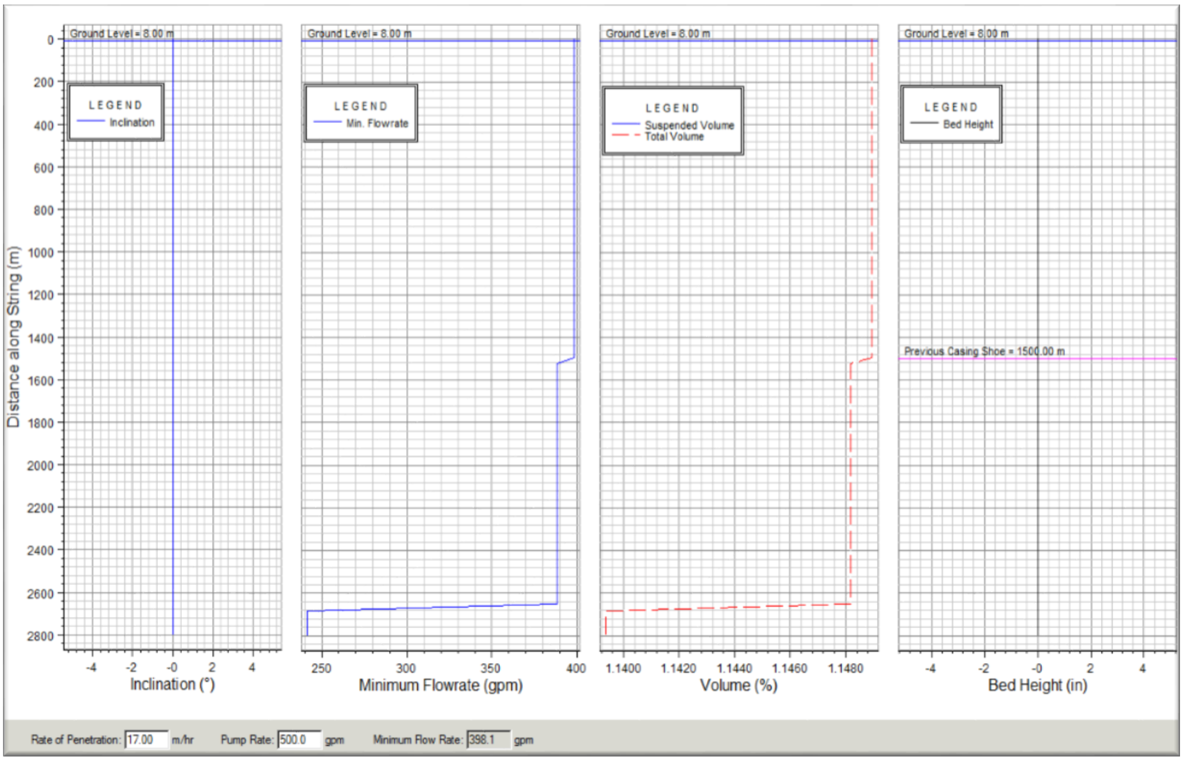

Figure 41: 12-1/4" Hydraulic transport parameters (Conventional case)

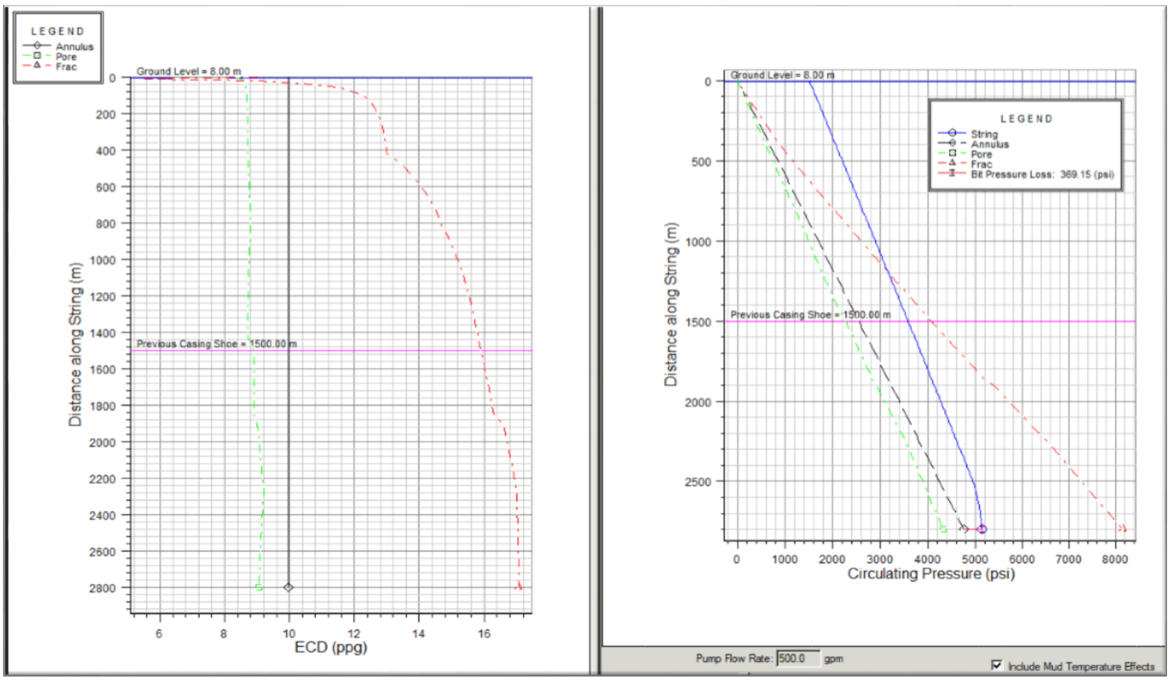

Figure 42: 12-1/4" ECD and Circulating Pressure vs Depth (Conventional case)

Circulating pressure and ECD vs depth shows one of the most important aspects of well control and effective hole cleaning as shown in *Figure 42*. The ECD of 9.7ppg mud is 10ppg which is well above the pore pressure line. ECD of the mud is between pore pressure (green dotted line) and fracture pressure (red dotted line). So the well is in good overbalanced condition. The blue line shows pressure in the string.

d) Intermediate hole (Torque & Drag: 12-1/4” hole@ 2800m)

Torque and tension graph is shown w.r.t depth. In the graph on the left, the torque limit of the top drive and make-up torque limits of tubulars are shown in red lines. Moving from right to the left are helical buckling, sinusoidal buckling, rotating on bottom, rotating off-bottom, tripping-in, tripping-out and back reaming. From right to the left, rotating on bottom requires high torque followed by back reaming, RIH while rotating and POOH while rotating slightly. In the graph on the right, tension in tons is shown (shown in *Figure 43*).

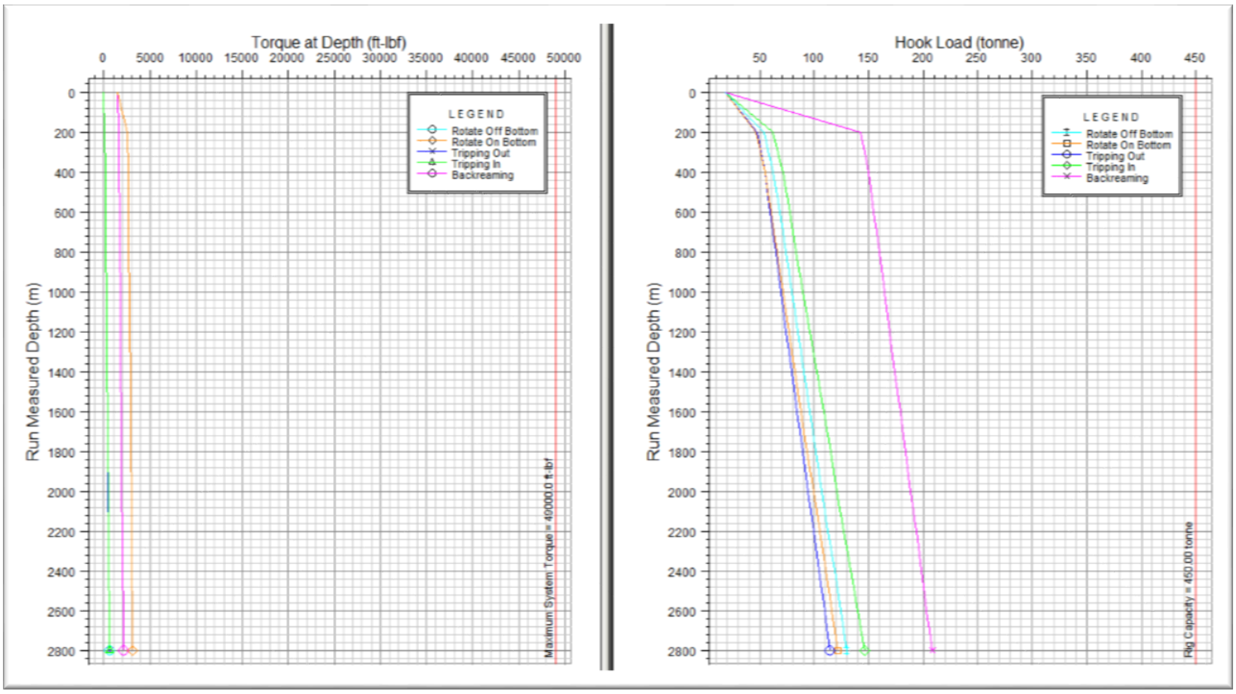

Figure 43: 12-1/4” Torque and Tension vs Distance along string

e) Production hole (Hydraulics: 8-1/2” hole@ 3550m)

For this hole minimum required flow-rate is 182gpm @100rpm and ROP of 10m/hr. The assigned flow-rate is 250gpm considering a certain level of working contingency and company past practices. Hydraulic cutting transport operational parameters graph shows inclination of the well, minimum flow-rate, suspended & total volume and bed height generation w.r.t distance along string. Volume and minimum flow rate requirements vary significantly in the BHA region and then becomes constant once it’s in the previous casing shoe at 2800m. The graph is shown below in *Figure 44.*

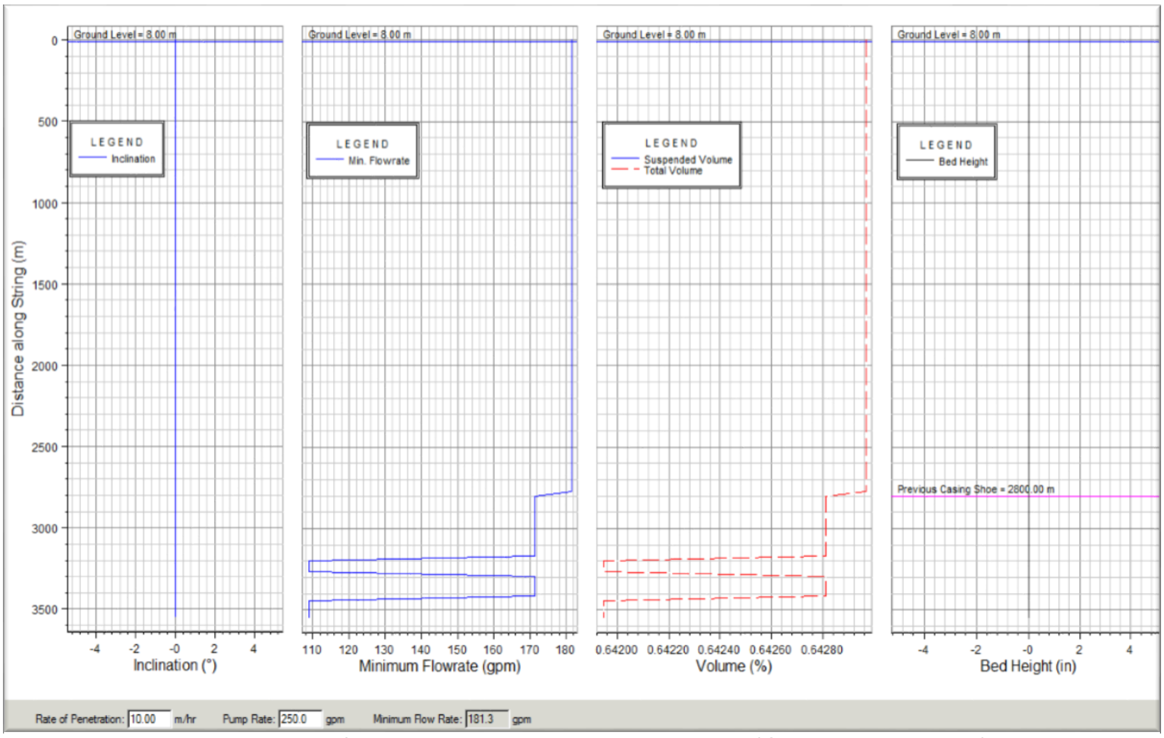

Figure 44: 8-1/2” Hydraulic transport parameters (Conventional case)

Circulating pressure and ECD vs depth shows one of the most important aspects of well control and effective hole cleaning. Bit pressure loss is 141psi which is 21% of total pressure loss as shown in *Figure 45.*

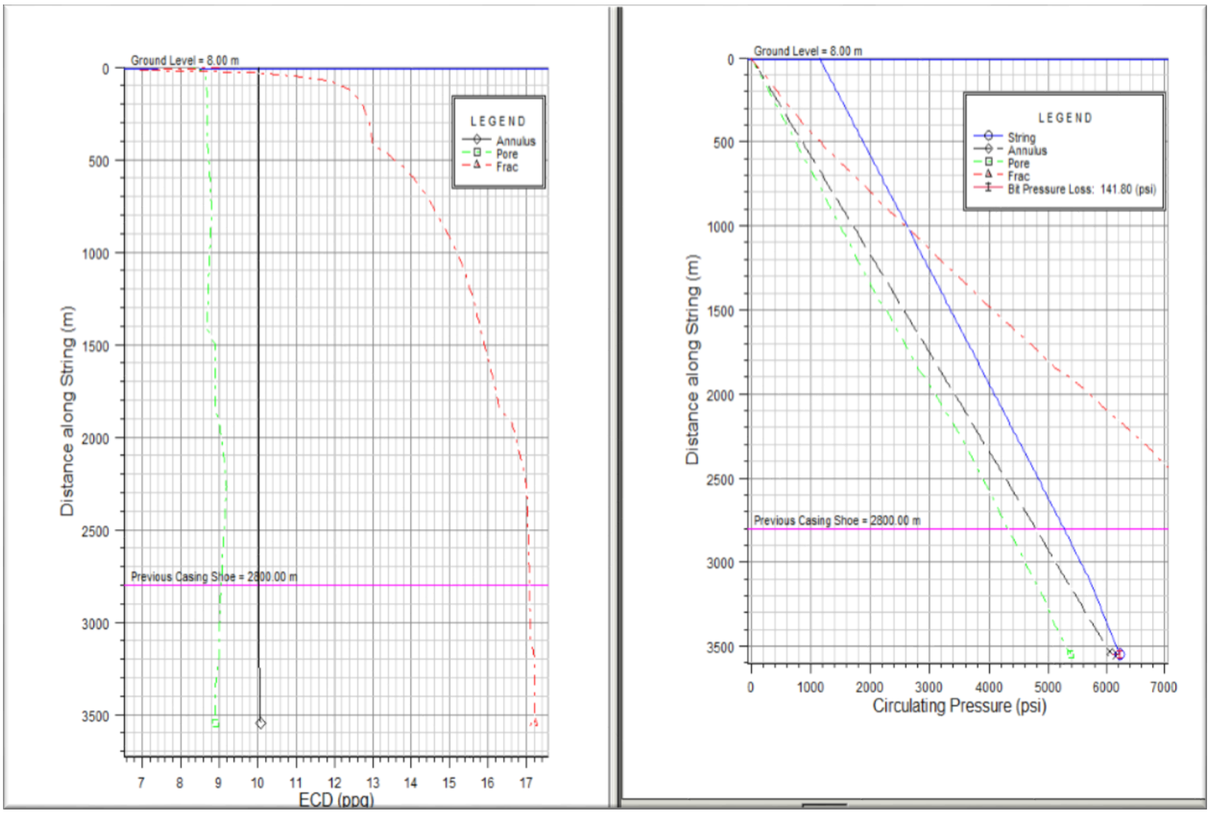

Figure 45: 8-1/2” ECD and Circulating Pressure vs Depth (Conventional case)

f) Production hole (Torque & Drag: 8-1/2” hole@ 3550m)

Graph on the left shows torque w.r.t depth. Lines from left to the right show tripping-in, tripping-out and off-bottom torques are around 1000ft-lbf. Back-reaming is expected to be at 3000ft-lbs while rotating on bottom is at 4000 ft-lbs. Dark red line shows make-up torques while right most red line shows maximum system torque at 49000ft-lbs.

Graph on the right shows Hook load. Tripping out and back reaming shows the same values. Dark red line shows maximum weight yield while right most red line shows maximum rig capacity of 450 tons. This is shown in *Figure 46.*

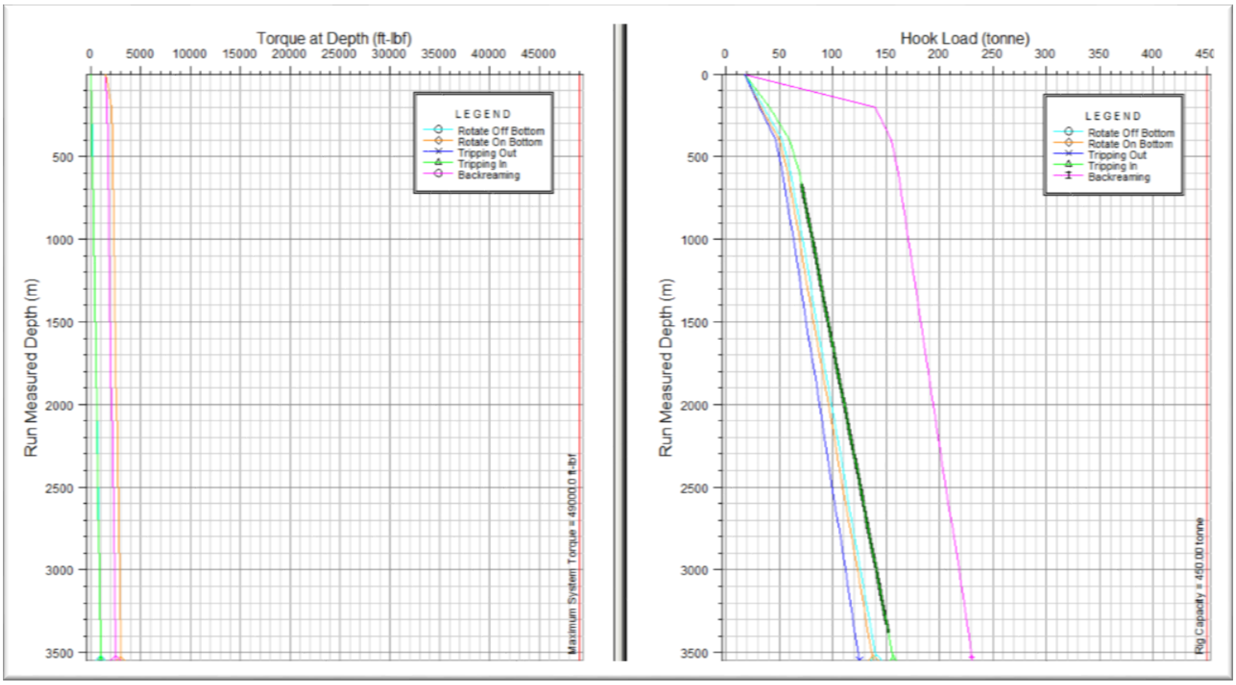

Figure 46: 8-1/2” Torque and Hook load vs Run Depth (Conventional case)

6.3.3 Well Summary (Conventional case)

Volume requirements for cement slurry are given below. Safety factors are just for lead slurry. It’s a common practice to pump only 100bbls of tail slurry. For liner cementing jobs only tail slurry is used. Surface hole has the maximum chances of uneven borehole and caving problems so double of the calculated amount is used. This is done to ensure that we have surface returns of cement. For all the subsequent hole sizes extra amount is kept in mind but it is less than the surface hole. They are based on drilling engineering practices within the business unit. Cement volume calculations are shown in *Table 7.*

Table 7: Cement Volume (Conventional Case)

Case 1A Conventional Case			
Hole Size	13-3/8” TOC @ 8m	9-5/8” TOC @ 1200m	7” TOC @ 2700m
Safety factor (Open hole)	1.00	0.5	0.3
Cement volume (bbl)	1211.00	423	90

Volume requirements for drilling fluid are given below. Safety factors for open hole and extra volume requirements are also shown. In surface hole there are chances of mud losses in large volumes. SML formation sometimes has nearby fractures which result in large volumes of mud losses. In one of the offset wells there was a loss of 2000bbls of mud. Even the spot pills were lost. So, after that experience, local section has a practice of making extra mud volumes. Also, fluid volumes from one section are used in the next section. This is shown in *Table 8.*

Table 8: Mud volumes (Conventional Case)

Case 1A Conventional Case			
Hole Size	17-1/2” @ 1500m	12-1/4” @ 2800m	8-1/2” @ 3550m
Hole volume(bbl)	1464.00	1477	1500
Safety factor	3.50	3	2.2
Mud required(bbl)	5130.00	4440.00	3300.00
New mud needed(bbl)	5130.00		

The final well summary is shown below in *Figure 47.* According to the normalized safety factors all the parameters are doing well. Only recommendation in this case is the alternate drift for intermediate casing. Two casing strings are used in intermediate casing to reduce the total cost. Metal to metal seal (Tenaris Blue) connections are used to avoid any type of casing connection leaks problems.

Well Summary

	String	OD/Weight/Grade	Connection	MD Interval (m)	Drift Dia. (in)	Minimum Safety Factor (Norm)			
						Burst	Collapse	Axial	Triaxial
1	Surface Casing	13 3/8", 68.000 ppf, L-80	BTC, HCP-110	8.00-1500.00	12.259	2.36	2.07	2.41	2.45
2									
3									
4	Intermediate Casing	9 5/8", 47.000 ppf, L-80	BTC, L-80	8.00-1500.00	8.625 A	1.49	1.74	1.28	1.42
5		9 5/8", 47.000 ppf, P-110	Tenaris Blue	1500.00-2800.00	8.625 A	2.12	1.04	1.66	1.87
6									
7									
8	Production Liner	7", 29.000 ppf, L-80	Tenaris Blue	2700.00-3550.00	6.059	1.74	1.16	1.09	1.15
9									
10									
11									
12	A Alternate Drift								
13									

Figure 47: Well Summary (Conventional case)

6.4 Case 1B Casing Drilling (CD) case

Casing drilling in the Miano wells is identified at two places. The first interval to drill is 500m interval in Ghazij and SML zone. Choice of interval is made, keeping in view the basic advantage of using casing drilling; which is its plastering effect. Ghazij and SML are the perfect places to use this technique because we cannot increase the mud weight and in the same time incur losses in loss circulation zone. The other section is Lower Goru shale zone which is drilled for 538m with casing drilling. Basic purpose of choosing is the contingency of having high pressures and chances of collapse in wellbore. Drilling this section will also result in increasing our confidence in casing drilling for further applications. This is shown below in *Table 9.*

Table 9: Well sections (Casing Drilling case)

Case 1B: Casing Drilling Case					
Type	**Depth (in-out)**	**Drilled section**	**Casing size**	**Bit/ Hole size**	**WFD casing drilling bit Code**
***Conv.**	60-1000m	940m	-	17-1/2”	-
****CD**	1000-1500m	500m	13-3/8”	17”	DPA 8516X
***Conv.**	1500-2262m	762m	-	12-1/4”	-
****CD**	2262-2800m	538m	9-5/8”	12”	DPA 4416X
***Conv.**	2800-3550m	750m	7”	8-1/2”	-
*Conv. = Conventional drilling			**CD = Casing drilling		

6.4.1 Well Plan (CD case)

Well plan is used for analysis of hydraulics and torque & drag of casing drilling case. It is described in detail in the section below.

a) Surface hole (Hydraulics: 17-1/2” hole @ 1000m)

Surface hole is drilled conventionally down to 1000m. ROP is 25m/hr, RPM’s are 100 and

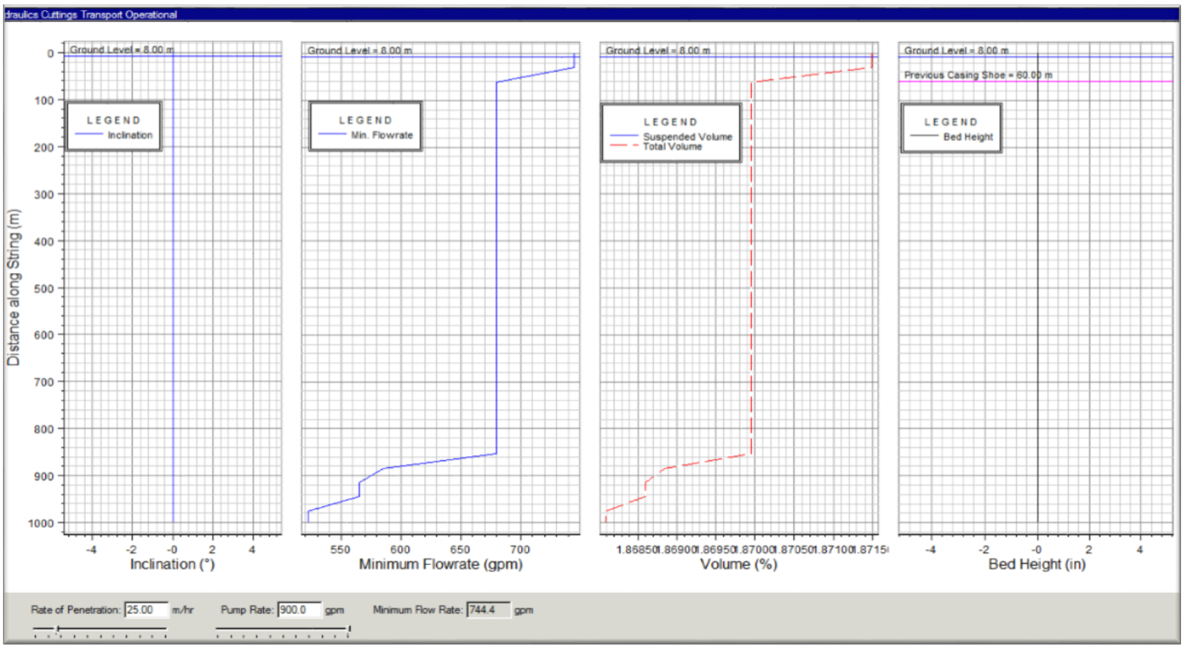

Figure 48: 17-1/2” Hydraulic transport parameters (CD case)

pump rate is 900gpm. The minimum flow rate is 745gpm in this case. Hydraulics of this section is shown in *Figure 48*. In hydraulic transport graph below 850m depth minimum flow-rate graph shows two distinct slopes (showing casing collar and HWDP region). This is due to changes in external diameter of BHA. Flow-rate required also increases in last 60m due to larger annulus. It is shown in *Figure 49.*

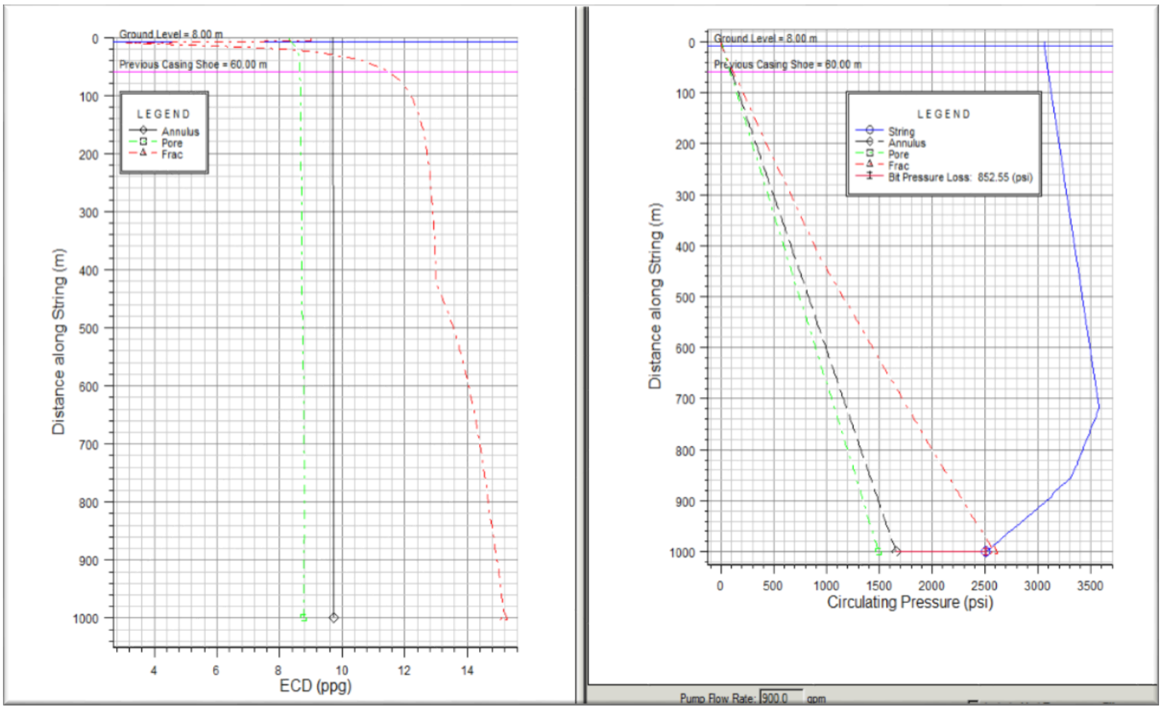

Figure 49: 17-1/2” ECD and Circulating Pressure VS Depth (CD case)

b) Surface hole (Torque and Drag: 17-1/2” @ 1000m)

Torque and hook load graph is shown w.r.t depth in *Figure 50*. In the graph on the left, the torque limit of the top drive and make-up torque limits of tubulars are shown in red lines.

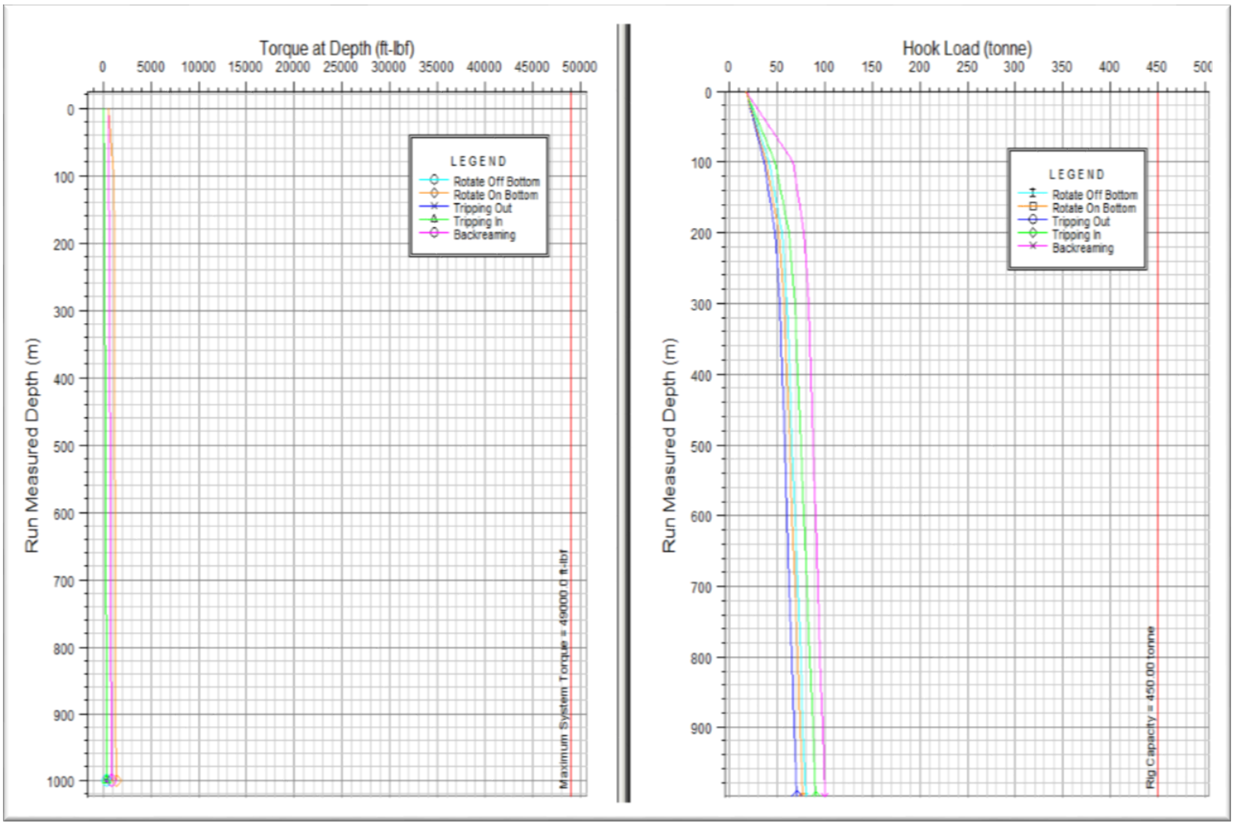

Figure 50: 17-1/2” Torque and Hook load vs Run Depth (CD case)

The other lines show rotating on bottom, rotating off-bottom, tripping-in, tripping-out and back reaming. From right to the left, rotating on bottom requires high torque followed by back reaming, RIH while rotating and POOH while rotating at low rpm. It should be noted that this graph is run measured depth, which means that top 200m section shows RIH of BHA. We make and Run-in the BHA first and then drill pipe.

c) Surface hole (Hydraulics: 13-3/8” x 17” @ 1500m)

First section is 1000m of 17-1/2” conventional drilling then we POOH and RIH 13-3/8” casing with 17” casing drilling (DPA 8516X) diamond bit. Remaining surface hole is drilled with casing for 500m (TD 1500m). ROP is 15m/hr, RPM’s are 100 and pump rate is 450gpm. The minimum flow rate is 320gpm in this case. Hydraulics of this section is shown in *Figure 51*. In hydraulic transport graph, at 1000m depth there is a sharp increase in minimum required flow-rate. This is due to larger annulus diameter.

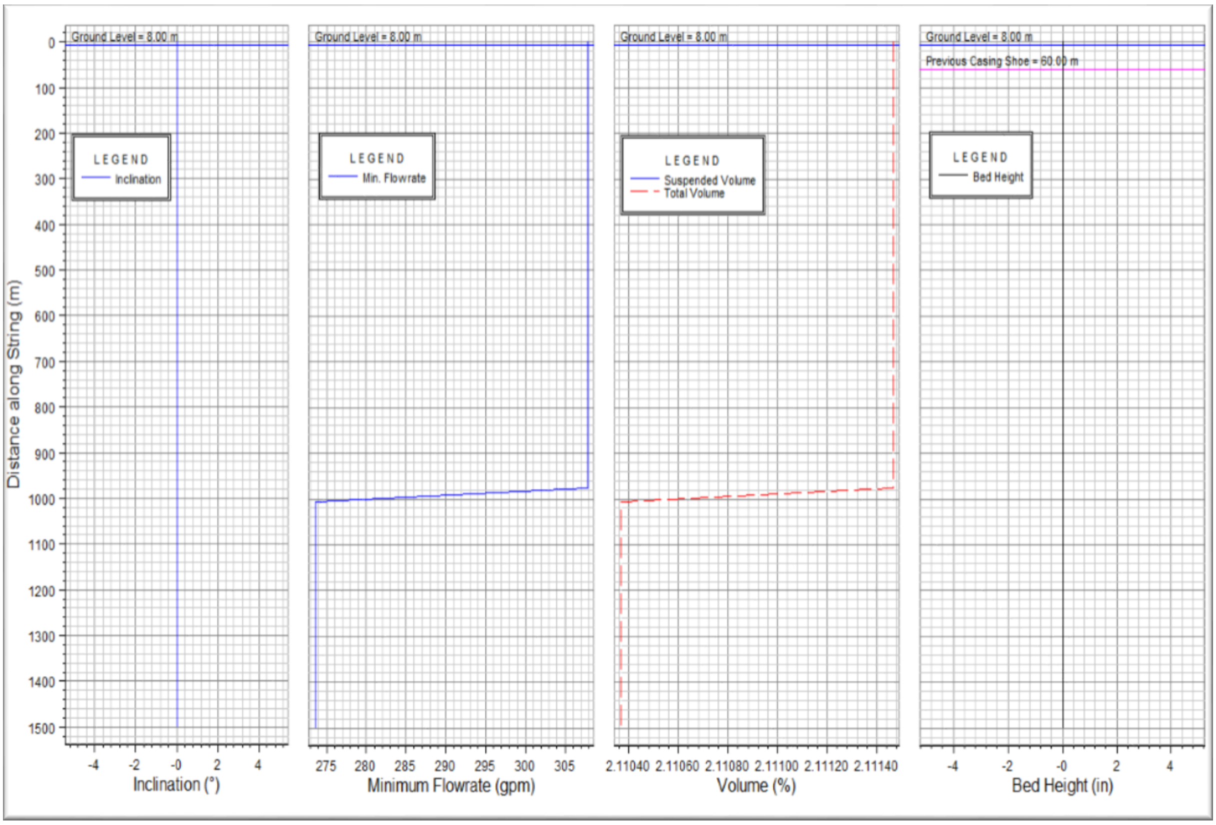

Figure 51: 13-3/8” x 17” Hydraulic transport parameters (CD case)

ECD of the mud is between pore pressure (green dotted line) and fracture pressure (red dotted line). So the well is in good overbalanced condition. The blue line shows pressure in the string. This is shown in *Figure 52.*

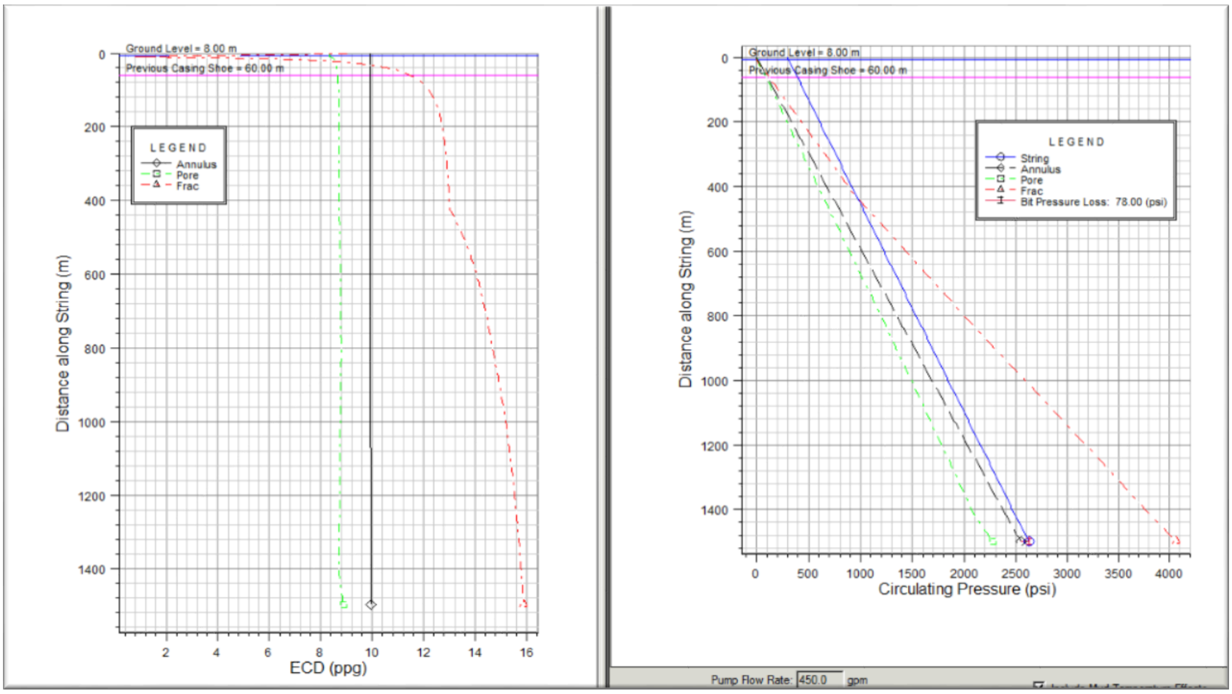

Figure 52: 13-3/8” x 17” ECD and Circulating Pressure VS Depth (CD case)

d) Surface hole (Torque and Drag: 17” @ 1500m)

Torque and tension graph is shown w.r.t distance along string in *Figure 53*. In the graph on the left, the torque limit of the top drive and make-up torque limits of tubular are shown in red lines. The other lines show rotating on bottom, rotating off-bottom, tripping-in, tripping-out and back reaming. From right to the left, rotating on bottom requires high torque followed by back reaming, RIH while rotating and POOH while rotating at low rpm.

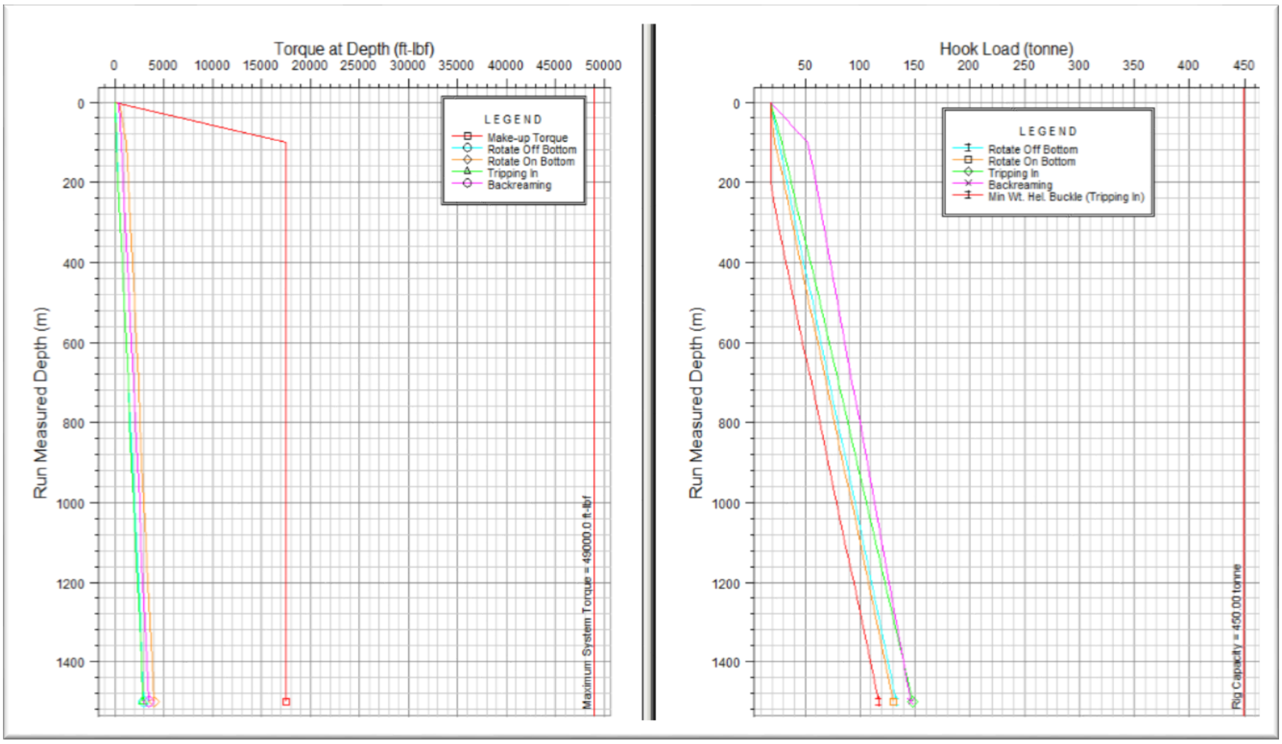

Figure 53: 13-3/8” x 17” Torque and Tension vs Depth (CD case)

The specifications of DPA bit used in Casing drilling are given in *Table 10* below. Detailed sheet is given in the **Appendix A**. Last column shows the parameters which are used to design the well model on landmark software. All our designed parameters are in line with the bit specifications.

Table 10: Casing drilling 17" bit specifications

DPA 8516X (17"x13-3/8") Casing Drilling	Min. required parameters	Max. permissible parameters	Parameters prognosis well
Torque(ft-lbs)	3500	*	4500
Flowrate (gpm)	550	1100	600
WOB (ton)	2.7	26	8.15
RPM	30	170	100
*90% of connection make-up torque			

e) Intermediate hole (Hydraulics: 12-1/4" @ 2262m)

Intermediate hole is drilled conventionally down to 2262m. ROP is 17m/hr, RPM's are 100 and pump rate is 500gpm. The minimum flow rate is 398gpm in this case. Hydraulics of this section is shown in *Figure 54*. In hydraulic transport graph below 2100m depth minimum flow-rate shows distinct slope (showing casing collar and HWDP region). This is due to changes in external diameter of BHA. Flow-rate required also increases after last casing shoe due to larger annulus.

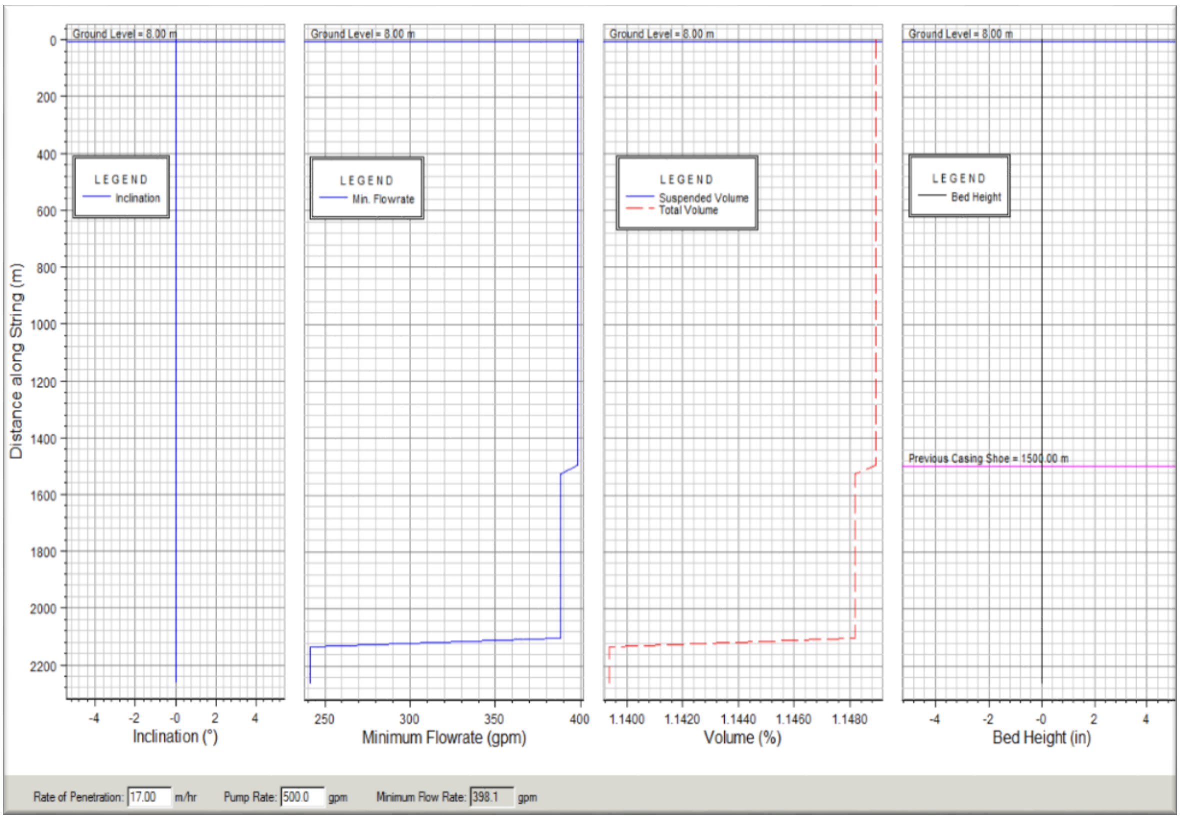

Figure 54: 12-1/4" Hydraulic transport parameters (CD case)

ECD of the mud is between pore pressure (green dotted line) and fracture pressure (red dotted line). So the well is in good overbalanced condition. The blue line shows pressure in the string. This is shown in *Figure 55.*

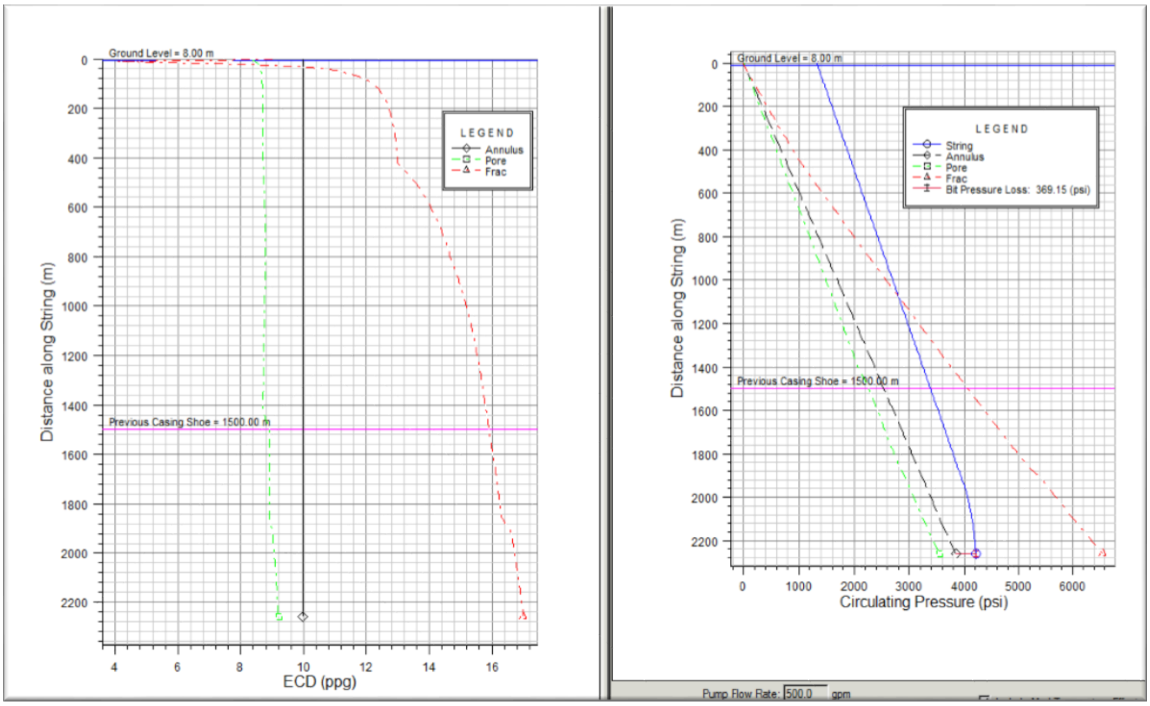

Figure 55: 12-1/4” ECD and Circulating Pressure VS Depth (CD case)

f) Intermediate hole (Torque and Drag: 12-1/4” @ 2262m)

Torque and tension graph is shown w.r.t distance along string in *Figure 56.* In the graph on the left, the torque limit of the top drive and make-up torque limits of tubulars are shown in red lines.

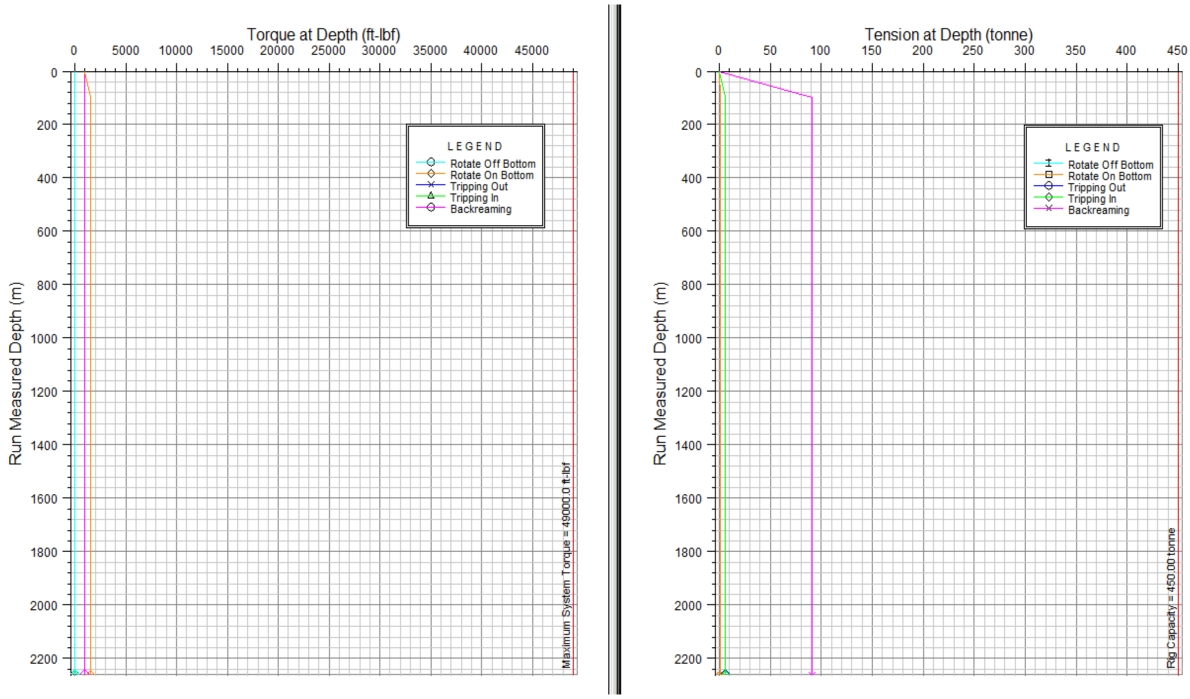

Figure 56: 12-1/4” Torque and Tension VS Depth (CD case)

Rotating on bottom has the highest torque. Tension in tons while doing different operations is shown; graph shows all the tension lines as expected.

g) Intermediate hole (Hydraulics: 9-5/8” x 12” @ 2800m)

First section is 2262m of 12-1/4” conventional drilling then we POOH and RIH 9-5/8” casing with 12” casing drilling (DPA 4416X) diamond bit. Casing drilling is done for 538m (TD 2800m). ROP is 12m/hr, RPM’s are 100 and pump rate is 300gpm. The minimum flow rate required is 180gpm in this case. In hydraulic transport graph, at 1000m and 2262m depths there is sharp increase in minimum required flow-rate. This is due to larger annulus diameter as shown in *Figure 57*.

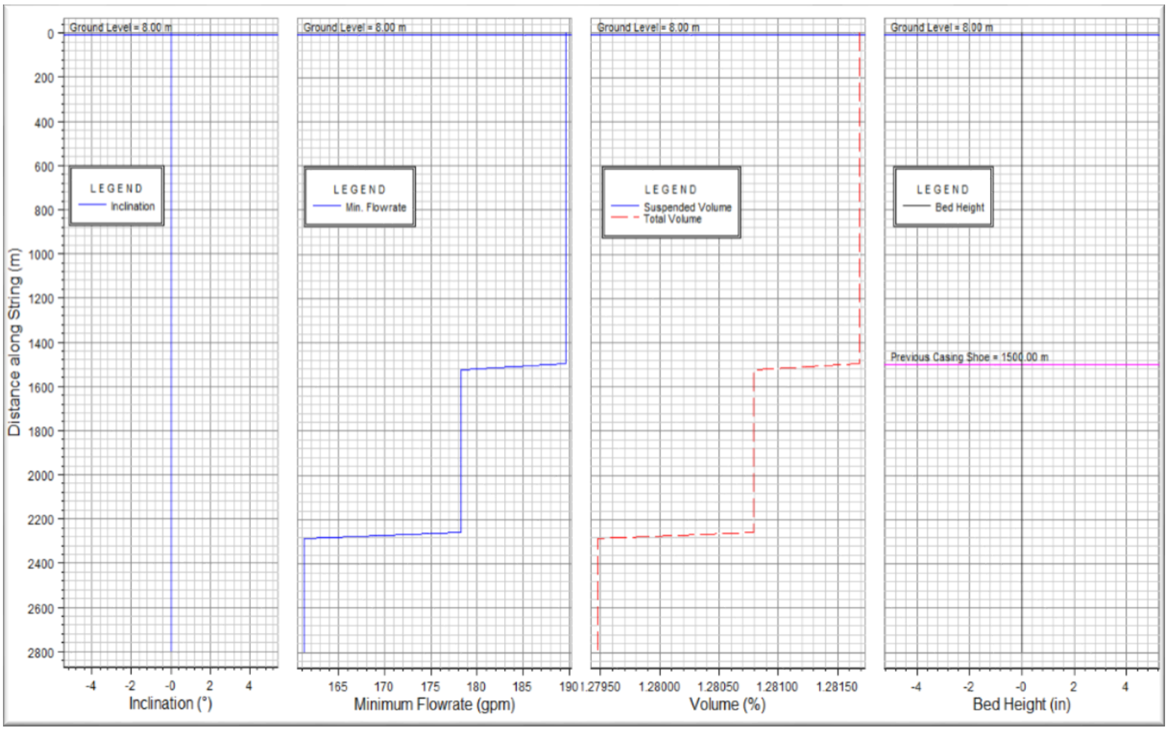

Figure 57: 9-5/8” x 12” Hydraulic transport parameters (CD case)

ECD of the mud is between pore pressure (green dotted line) and fracture pressure (red dotted line). So the well is in good overbalanced condition. The blue line shows pressure in the string. This is as shown in *Figure 58.*

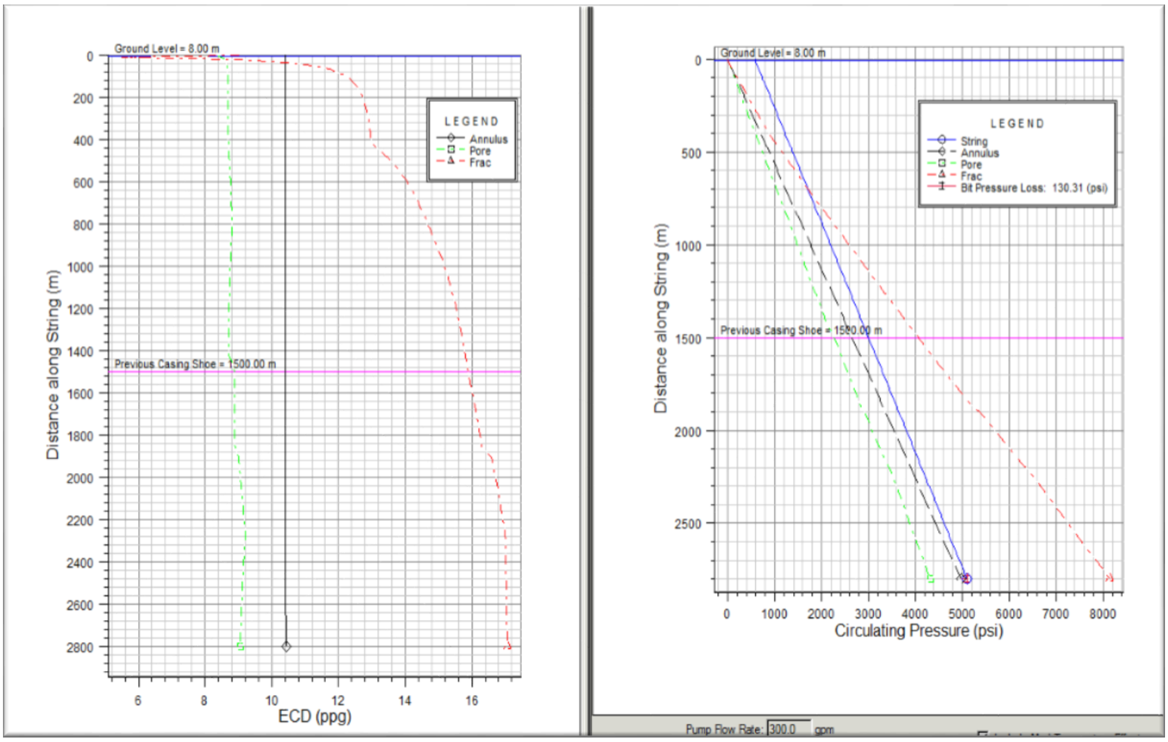

Figure 58: 9-5/8" x 12" ECD and Circulating Pressure VS Depth (CD case)

The specifications of Casing drilling bit are given in Table 11 below. Detailed sheet is given in the ***Appendix A***. Last column shows the parameters which are used to design the well model on landmark software. All our planned parameters are in line with the bit specifications.

Table 11: Casing drilling 12" bit specifications

DPA 4416X (12"x9-5/8") Casing Drilling	Min. required parameters	Max. permissible parameters	Planned Parameters prognosis well
Torque(ft-lbs)	1500	*	2500
Flow-rate (gpm)	250	500	300
WOB (ton)	3	25	4.3
RPM	40	200	100
*90% of connection make-up torque			

h) Intermediate hole (Torque and Drag: 12" @ 2800m)

Torque and tension graph is shown w.r.t distance along string as shown in *Figure 59*. In the graph on the left, the torque limit of the top drive and make-up torque limits of tubulars are shown in red lines. The other lines show rotating on bottom, rotating off-bottom, tripping-in, tripping-out and back reaming which are according to the standard practices.

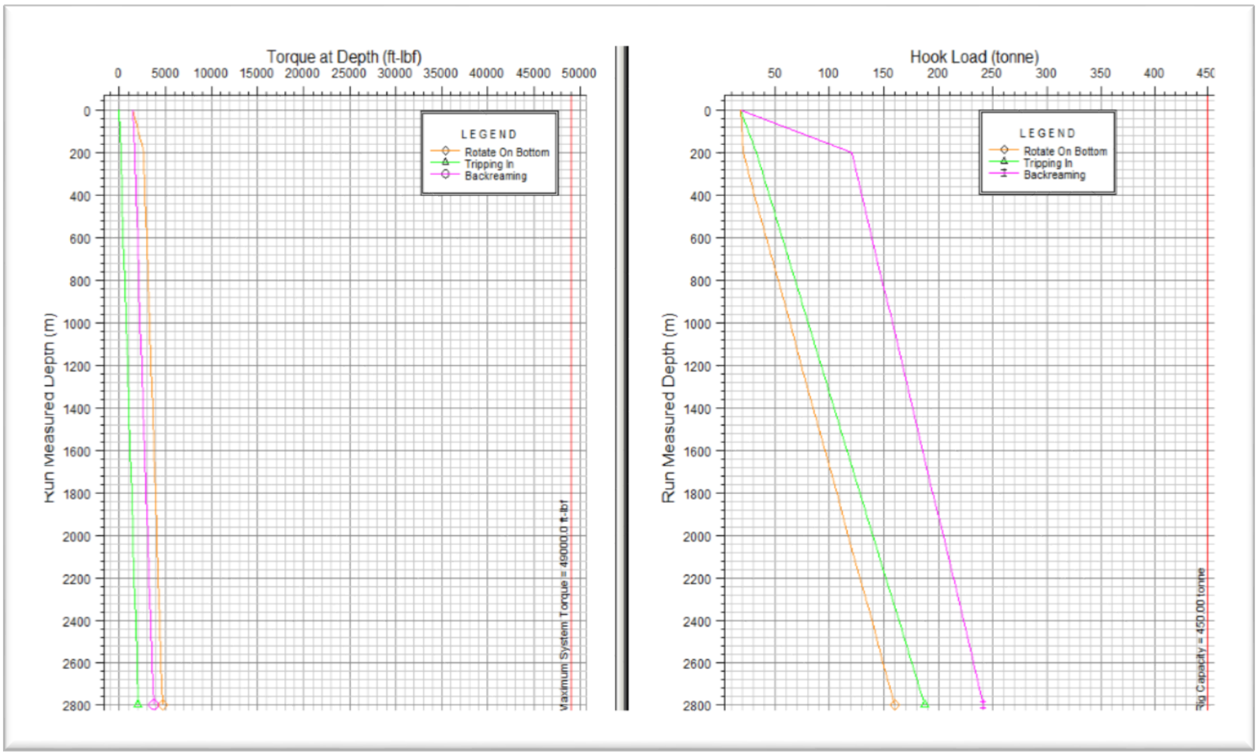

Figure 59: 9-5/8” x 12” Torque and Tension VS Depth (CD case)

8-1/2” hole and 7” casing of Convectional and CD case are exactly the same. So, refer to section 6.3.1 (e)f) for stress check, 6.3.2 e) for hydraulics and section 6.3.2 (f) for Torque and Drag.

6.4.2 Well Summary

Volume requirements for cement slurry are given below. Safety factors are just for lead slurry. It’s a common practice to pump only 100bbls of tail slurry. Safety factor is high for surface section as there are more chances of caving problem in top hole section due to loose sand. As we go deeper, formations are more competent and need less safety factor. This is shown in *Table 12.*

Table 12: Cement Volume (CD case)

Case 1B: CD case			
Hole Size	13-3/8” TOC @ 8m	9-5/8” TOC @ 1200m	7” TOC @ 2700m
Safety factor (Open-hole)	1.00	0.5	0.3
Cement volume (bbl.)	1156	405	90

Volume requirements for drilling fluid are given below. Safety factors for open hole and extra volume requirements are also shown. Safety factors are higher in surface section due to loose sands. Fluid from one section is used in the next section. So, major volume is made on well spud followed by some modifications as required in each hole section. Mud volume requirements are given in *Table 13.*

Table 13: Mud volumes (CD case)

Case 1B: CD case			
Hole Size	17-1/2” @ 1500m	12-1/4” @ 2800m	8-1/2” @ 3550m
Hole volume(bbl)	1464.00	1477	1500
Safety factor	3.00	2.5	2.2
Mud required(bbl)	4400.00	3700.00	3300.00
New mud needed(bbl)	4400.00		

Figure 60 shows normalized minimum safety factors which are all in-line with drilling engineering practices. Only recommendation in this case is the alternate drift for intermediate casing. Two casing strings are used in intermediate casing to reduce the total cost. Metal to metal seal (Tenaris Blue) connections are used to avoid any type of casing connection leaks problems.

Well Summary

	String	OD/Weight/Grade	Connection	MD Interval (m)	Drift Dia. (in)	Minimum Safety Factor (Norm)			
						Burst	Collapse	Axial	Triaxial
1	Surface Casing	13 3/8", 68.000 ppf, L-80	BTC, HCP-110	8.00-1500.00	12.259	2.36	2.07	2.41	2.45
2									
3									
4	Intermediate Casing	9 5/8", 47.000 ppf, L-80	BTC, L-80	8.00-1500.00	8.625 A	1.49	1.74	1.28	1.42
5		9 5/8", 47.000 ppf, P-110	Tenaris Blue	1500.00-2800.00	8.625 A	2.12	1.04	1.66	1.87
6									
7									
8	Production Liner	7", 29.000 ppf, L-80	Tenaris Blue	2700.00-3550.00	6.059	1.74	1.16	1.09	1.15
9									
10									
11									
12	A Alternate Drift								
13									

Figure 60: Well Summary (CD case)

6.5 Case 2 Slim-bore Case (Casing and Liner drilling)

This case has a slightly different philosophy. It is based on the fact that production department only run the completions of 3-1/2” on each well. Keeping that in view it was decided to make a slim bore well in which last liner is 4-1/2” in 6” hole.

Like Conventional and CD case, slim bore case is also a three string casing design. Structural (conductor) casing is 13-3/8” diameter and only goes down to 60m. Surface casing is at the depth of 1500m (same as CD case). Intermediate section is liner and is down to 2600m. The production string is also a Liner which goes down to 3550m approximately. Well schematics are shown in *Figure 61*. Well prognosis is attached in ***Appendix C***.

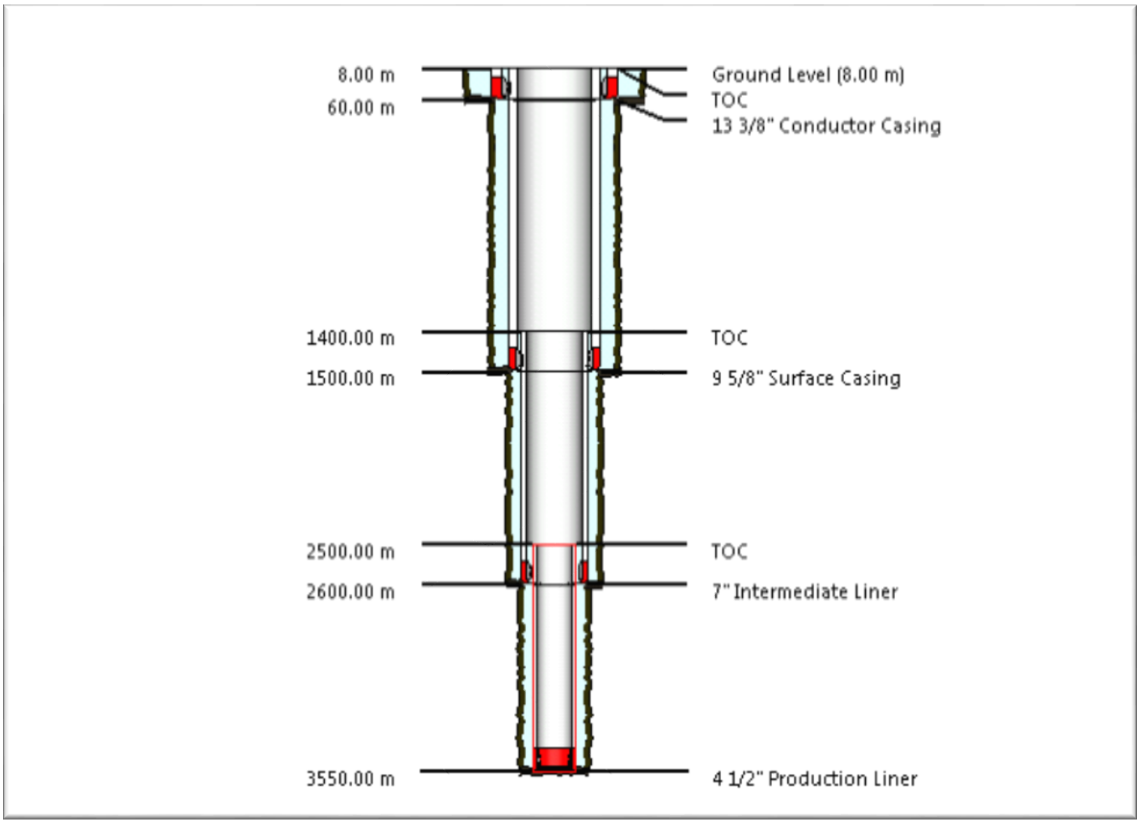

Figure 61: Well schematics (Slim-bore case)

6.5.1 Compass design

First casing is set just at the shoe of SML formation (same as case 1). Snapshot of schematics from Compass is shown below. It shows the casing setting depths and formation tops. This is shown in *Figure 62.*

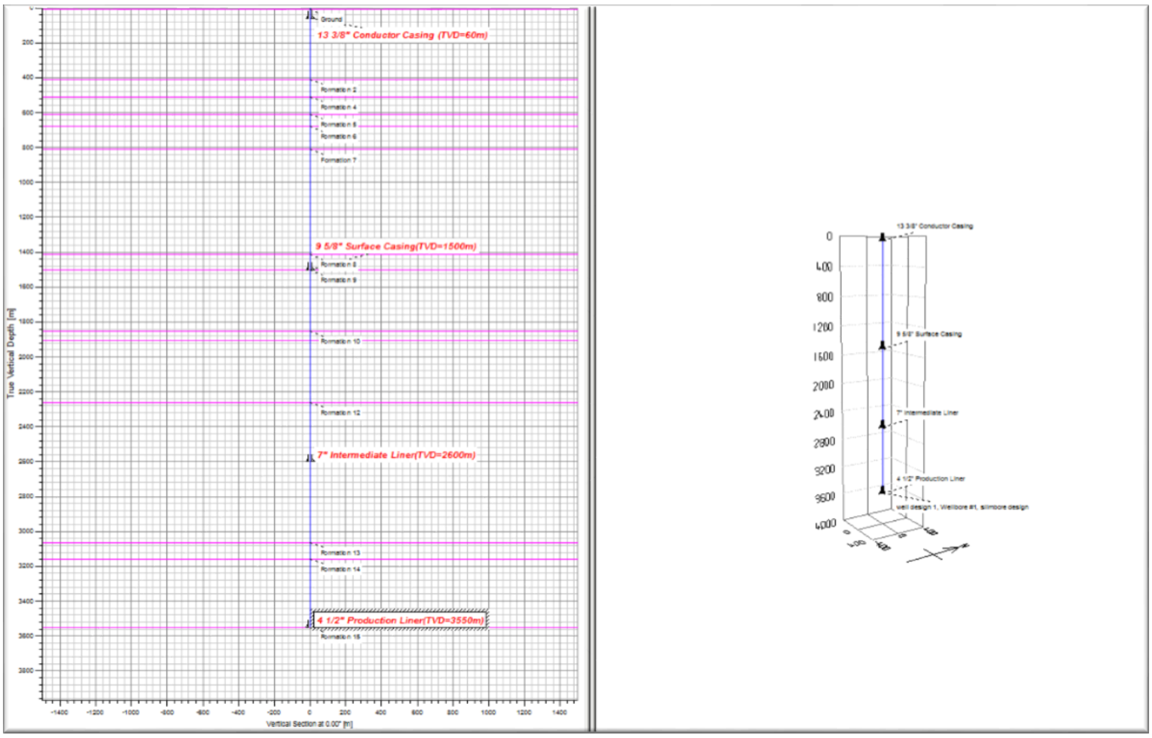

Figure 62: Section view (Slim-bore case)

a) Stress-check design

Casing tubular design is considered keeping in view the entire contingency factors available in stress-check. Casing selection is done on basis of availability of the casing strings in the inventory of the company.

b) Well plan design

Well plan design of this slim-bore case is also made and checked for all its engineering practices. The basic ideas and practices for this well design remains the same but absolute values do differ.

6.5.2 Well Summary

Following section is designed to be drilled with casing & liner drilling technique. The drilling depths are the same as selected for CD case, only difference is in the diameter of wellbore and use of liner drilling (LD) for drilling 7" liner. This is shown in *Table 14.*

Table 14: Well sections

Case 2: Slim-bore Case					
Type	Depth (in-out)	Drilled section	Casing size	Bit/ Hole size	WFD Defyer bit Code
Conv.	60-1000m	940m	-	12-1/4"	-
CD	1000-1500m	500m	9-5/8"	12"	DPA 4416X
Conv.	1500-2262m	762m	-	8-1/2"	-
*LD	2262-2600m	338m	7"	8-1/2"	DPA 5513X
Conv.	2600-3550m	950m	4-1/2"	6"	-
	*LD	Liner Drilling			

Volume requirements for cement slurry are given below in *Table 15*. Safety factors are just for lead slurry. It's a common practice to pump only 100bbls of tail slurry. The liners are fully cemented with tail slurry. This is in conjunction with drilling practices within OMV.

Table 15: Cement Volume (Slim-bore case)

Case 2 Slim-bore Case			
Hole Size	9-5/8" TOC @ 8m	7" TOC @ 1400m	4-1/2" TOC @ 2500m
Safety factor (Openhole)	1.00	0.5	0.3
Cement volume (bbl)	530.00	133	58

Volume requirements for drilling fluid are given below. Safety factors for open hole and extra volume requirements are also shown. Fluid from one section is used in the next section. This volume calculation is shown in *Table 16.*

Table 16: Mud volumes (Slimbore case)

Case 2 Slimbore Case			
Hole Size	12-1/4" Hole @ 1500m	8-1/2" Hole @ 2600m	6" Hole @ 3550m
Hole volume(bbl)	718.00	645	406
Safety factor	3.00	2.5	2.2
Mud required(bbl)	2160.00	1620.00	900.00
New mud needed(bbl)	2160.00		

The specifications of DPA bit used in Casing and liner drilling are following in *Table 17.* Detailed sheet is given in the ***Appendix A***. Last column shows the compliance of our model with the specifications. Non-retrievable bit will be used for DwL™ operations. Liner will be run on drill pipes. Hydraulically actuated hanger system will be used. Poppet valve will be used in float collar. Hanger and float collar will be run in the liner during RIH.

Table 17: Casing drilling bit specifications

DPA 4416X (12"x9-5/8") Casing Drilling	Min. required parameters	Max. permissible parameters	Planned Parameters (prognosis well)
Torque(ft-lbs)	1500	*	2500
Flowrate (gpm)	250	500	300
WOB (ton)	3	25	4.3
RPM	40	200	100
DPA 5513X (8-1/2"x7") Liner Drilling			
Torque(ft-lbs)	1000	*	2500
Flowrate (gpm)	120	240	300
WOB (ton)	3	24	4.3
RPM	50	200	100
*90% of connection make-up torque			

Figure 63 shows normalized minimum safety factors which are all in-line with drilling engineering practices. Only recommendation in this case is the alternate drift for intermediate casing. Two casing strings are used in intermediate casing to reduce the total cost. Metal to metal seal (Tenaris Blue) connections are used to avoid any type of casing connection leaks problems.

Well Summary

	String	OD/Weight/Grade	Connection	MD Interval (m)	Drift Dia. (in)	Minimum Safety Factor (Norm)			
						Burst	Collapse	Axial	Triaxial
1	Conductor Casing	13 3/8", 68.000 ppf, P-110	BTC, HCP-110	8.00-60.00	12.259	4.18	64.88	7.60	4.68
2									
3									
4	Surface Casing	9 5/8", 47.000 ppf, P-110	Tenaris Blue	8.00-1500.00	8.625 A	2.04	1.94	2.53	2.19
5									
6									
7	Intermediate Liner	7", 29.000 ppf, P-110	Tenaris Blue	1400.00-2600.00	6.059	2.24	1.79	1.74	1.80
8									
9									
10	Production Liner	4 1/2", 13.500 ppf, P-110	Tenaris Blue	2500.00-3550.00	3.795	2.60	1.76	1.53	1.62
11									
12									
13									
14	A Alternate Drift								

Figure 63: Well Summary (Slim-bore case)

6.6 Economic Analysis

Economic analysis of the three cases was done and DWOP was generated for each individual well. Costs for all the similar operations were kept same while extra drilling costs due to CD and LD applications were put in the respective cases.

6.6.1 Case 1A: Conventional case

Final summary of the conventional case is given below in *Table 18*. Costs are based on actual contracts in place and are in line with current AFE assumptions used for OMV Pakistan well engineering gate process. All the costs are realistic and in line with drilling engineering practices. Miscellaneous costs of the well includes day rates of field and office staff, logistics, inspection charges, communication rentals, para medics and security guards.

Table 18: Miano well cost summary (Conventional case)

Miano NN WELL: TD 3550 m TVD/MD	
Cost Categories	**Million USD**
Location costs	$0.60
Total Costs for Rig, Rig Move, Fuel and Water supply	$1.94
Water based drilling fluid mud incl. Solid control	$0.52
Tubulars (Casings: 13-3/8", 9-5/8",7")	$1.13
Well heads X-tree	$0.38
Bit and Downhole Tools	$0.33
Cementing	$0.27
Fishing and rentals	$0.10
Directional services	$0.00
Liner hanger	$0.07
Logging and formation evaluation incl. CBL, VDL & coring	$0.54
Completions and CIT	$0.94
Miscellaneous	$0.72
Total cost of the well without contingency	$7.53
Total cost with 5% contingency	**$7.91**
Days in total	38.7 days

ROP for drilling is predicted from Miano 19. Miano-19 is a latest offset well. ROP data is extracted from ProNova software. The ROP's for prognostic well with casing drilling application at two different depths are assumed and are used to make Time vs Depth curve in Microsoft excel. The assumed ROP are shown in *Table 19*.

Table 19: Offset and prognosis well ROP (Conventional case)

Hole Size	Miano-19(offset well)		Prognosis well	
	Drilled depths (m)	Av. ROP(m/hr)	Hole Depth selected	ROP assumed
17.5"	60-1000	25.8	60-1500	20
12.25"	1000-2300	17.7	1500-2800	15
8.5"	2300-3550	12.6	2800-3550	10

Planning the time required for drilling a well is based on number of operations. All operations are assigned time; keeping in view the past experience, company policies and standard oil field practices. Excel sheet was made with time allocation to every step involved in well construction. Phase wise time breakdown is shown in *Table 20*.

Table 20: Time breakdown (Conventional Drilling)

Miano-NN Conventional Case			
Operation	Section Time	Depth	Cum. Time
	Days	m	Days
Spud	0	60	0
Drill 17 1/2" hole section	6	1000	6
Run 13 3/8" CSG and cementing	2	1500	7
Drill 12 1/4" Hole	6	2262	13
Run 9-5/8" CSG and cementing	2	2800	15
Drill 8 1/2" hole	3	3361	18
Drill 8 1/2" hole to well TD	1	3550	19
Wiper trip	1	3550	20
Logging	3	3550	23
Run 7" LINER and cementing	3	3550	26
Completion	10	3550	35.6
Contingency (10% on Drilling time)	3	3550	38.7
Total time			**38.7**

Summary of time statistics for the wellbore is shown in *Table 21*. Time for drilling a well, logging, last liner run and completions time along with 10% contingency on drilling time plus one extra day.

Table 21: Time summary of conventionally drilled well

Well statistics	Time
Time (Dry hole)	20 days
Time (7" Liner)	3 days
Logging	3 days
Completion	10 days
Contingency 10%	3 days
Time on Well	38.7 days

Time vs drilled depth and time vs bit depth of conventional case is given in *Figure 64*. Different phases and their corresponding operations are given below in *Table 22*. All the round trips visible are planned trips. Any trip other than this will be unplanned and will be included in non-productive time. Two casing points at 1500m and 2800m depth and one liner point at 3550m TD can be seen by long flat sections. These flat times includes casing RIH, cementing, wellhead and BOP installation time. Last extended flat time includes time for logging, Liner RIH & cementing, completions, perforations, flow back and testing activity.

Drilling of last (8-1/2") section and all the operational time after it is kept the same for conventional case and casing drilling case. Viper trips are performed. This is done to keep the well stabilized and this practice is observed in offset wells. Viper trips at 1000m, 1500m and 1900m are planned. They are the most vulnerable sections and need good borehole stability. Reaming is done after drilling each drill pipe stand in unstable zones or as required.

At last, 10% contingency on drilling time is added. This contingency in time and cost is now considered as a standard practice.

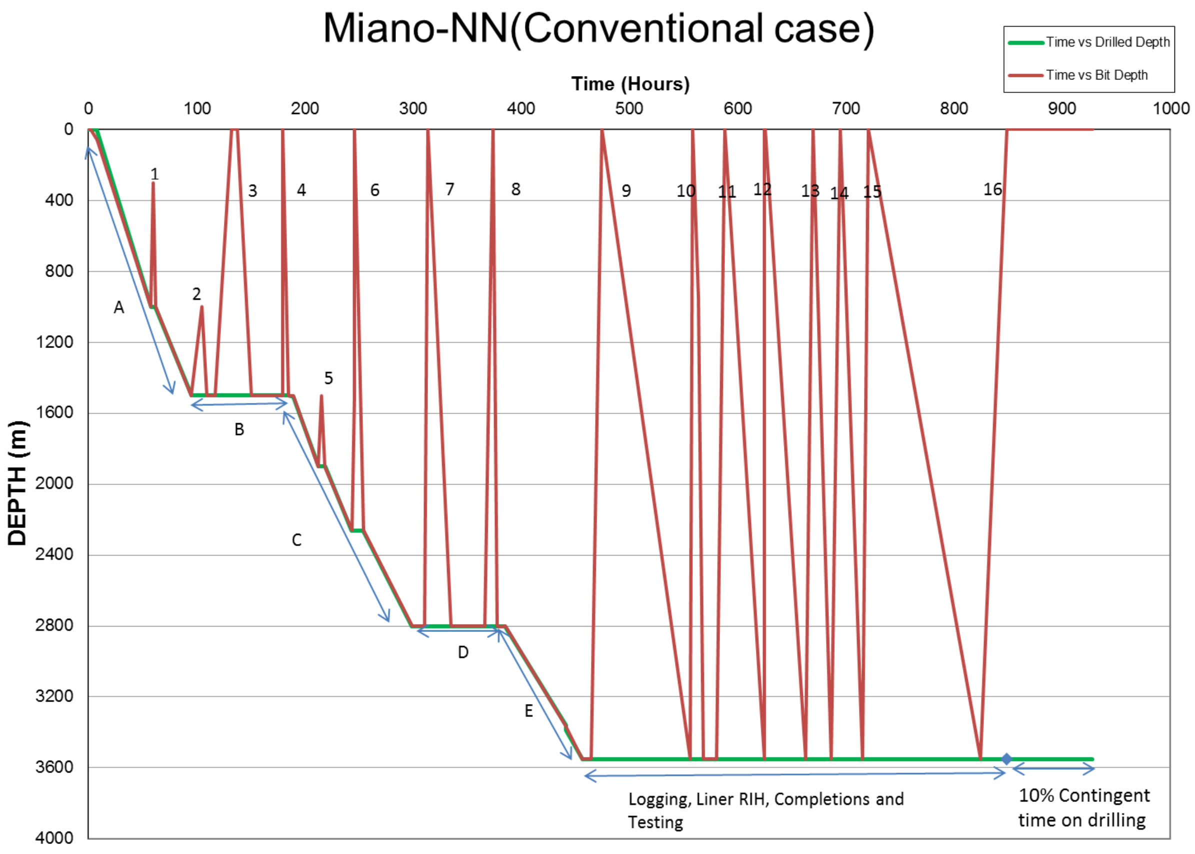

Figure 64: TVD ("Miano NN" Conventional Case)

Table 22: Different Phases of Conventional well

Phase	Operation	Tripping	Operation
A	Drill 17-1/2" section	1	Wiper trip
B	Flat time	2	Wiper trip
C	Drill 12-1/4" section	3	Casing RIH 13-3/8"
D	Flat time	4	RIH DP TOC
E	Drill 8-1/2" Hole	5	Wiper trip
		6	Formation Evaluation
		7	Casing RIH 9-5/8"
		8	RIH DP TOC
		9	Wire line logging
		10	7" Liner job
		11	Liner Cleanout
		12	RIH 3.5" completions
		13	Slick line
		14	Coil tubing
		15	Wireline
		16	Final POOH

6.6.2 Case 1B: Casing Drilling (CD) case

Final summary of the casing drilling case is given below in *Table 23*. Only extra cost in this case is "casing drilling" cost. Some time is saved due to casing drilling activity which in turn saves some cost. Approximately 1000m of casing drilling in two separate sections save USD

0.18 million. Although total time is saved by 2.6 days but total cost saved is not much due to extra costs of casing drilling and drilling of only a part of section instead of the whole section.

Table 23: Miano well cost summary (CD case)

Miano NN WELL: TD 3550 m TVD/MD	
Cost Categories	**Million USD**
Location costs	$0.60
Total Costs for Rig, Rig Move, Fuel and Water supply	$1.85
Water based drilling fluid mud incl. Solid control	$0.45
Tubulars (casings: 13-3/8”, 9-5/8”,7”)	$1.13
Well heads X-tree	$0.38
Bit and Downhole Tools	$0.24
Cementing	$0.27
Fishing and rentals	$0.10
Directional services	$0.00
Liner hanger	$0.07
Logging and formation evaluation incl. CBL, VDL, coring	$0.54
Completions and CIT	$0.94
Miscellaneous	$0.68
Extra cost due to Casing Drilling	$0.12
Total cost of the well without contingency	$7.36
Total cost with 5% contingency	**$7.73**
Days in total	36.1 days

ROP for drilling is predicted from Miano 19. Miano-19 is a latest offset well. ROP data is extracted from ProNova software. The ROP’s for prognostic well with casing drilling application at two different depths are assumed and are used to make Time vs Depth curve in Microsoft excel. The assumed ROP are shown in *Table 24*.

Table 24: Offset and prognosis well ROP (Casing Drilling case)

Hole Size	Miano-19(offset well)		Prognosis well	
	Drilled Depth (m)	Av. ROP(m/hr)	Hole depth selected	ROP assumed
17.5"	60-1000	25.8	60-1000	20
13-3/8" CD			1000-1500	15
12.25"	1000-2300	17.7	1500-2260	15
9-5/8" CD			2260-2800	12
8.5"	2300-3550	12.6	2800-3550	10

Planning the time required for drilling a well is based on number of operations. All operations are assigned time; keeping in view the past experience, company policies and standard oil field practices. Casing drilling saves some time as compared to conventional drilling. Excel sheet was made with time allocation to every step involved in well construction. Phase wise time breakdown is shown in *Table 25*.

Table 25: Time Breakdown (Casing Drilling)

Miano-NN Casing Drilling Case			
Operation	**Section time**	**Depth**	**Cum. Time**
	Days	m	Days
Spud	0	1000	0
Drill 17 1/2" hole section	5	1000	5
Run 13 3/8" CSG	1	1500	6
Drill 12 1/4" Hole	6	2262	12
Run 9-5/8" CSG	1	2800	13
Drill 8 1/2" hole	3	3361	16
Drill 8 1/2" hole to well TD	1	3550	17
Wiper trip	1	3550	17
Logging	3	3550	21
Run 7" LINER	3	3550	24
Completion	10	3550	33
Contingency 10% on Drilling	3	3550	36
Total			**36.1**

Summary of time statistics for the wellbore is shown in *Table 26*. Time for drilling a well, logging, last liner run and completions time along with 10% contingency on drilling time plus one extra day.

Table 26: Time summary of casing drilling case

Well statistics	**Time**
Time (Dry hole)	17 days
Time (7" Liner)	3 days
Logging	3 days
Completion	10 days
Contingency 10%	3 days
Time on Well	36.1 days

Time vs drilled depth and time vs bit depth of casing drilling case is shown in *Figure 65*. Each phase of TxD curve is shown in *Table 27*. There are two casing drilling sections. Section-1 is from 1000-1500m and section-2 is from 2262-2800m. All the other sections are drilled conventionally. All the drilling operations between casing drilling case and conventional drilling case are logically the same including wiper trips. Operations after 9-5/8” cementing and all the following events and their corresponding times are exactly the same. Casing points are kept the same at 1500m and 2800m depth (as in conventional case) and can be seen from flat spots. There is a contingent wiper trip at 1000m, 1500m and 2300m.

Two casing points at 1500m and 2800m depth and one liner point at 3550m TD is selected (same as in conventional drilling).

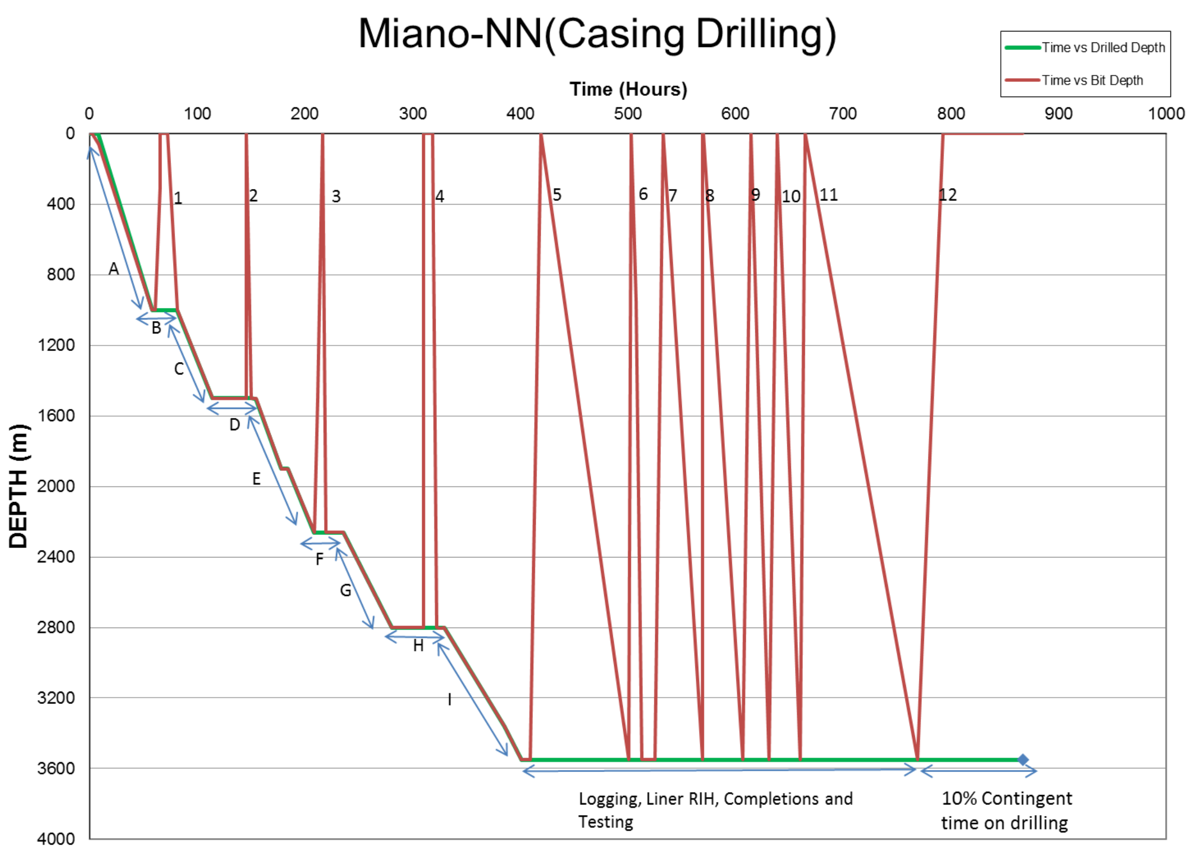

Figure 65: TVD ("Miano NN" Casing Drilling Case)

Table 27: Different phases of Casing Drilling well

Phase	Operation	Tripping	Operation
A	Drill 17-1/2" section	1	RIH Casing with bit
B	Flat time	2	RIH DP TOC
C	Drill with casing	3	Formation Evaluation
D	Flat time	4	RIH Drill pipe
E	Drill 12-1/4" section	5	Wire line logging
F	RIH Casing with bit	6	7" Liner job
G	Drill with casing	7	Liner Cleanout
H	Flat time	8	RIH 3.5" completions
I	Drill 8-1/2" section	9	Slick line
		10	Coil tubing
		11	Wireline
		12	Final POOH

a) Difference between casing drilling and conventional drilling

Major difference is that we have shorter flat times in casing drilling case. The time is saved because of less tripping of pipes in and out of the hole. Once the casing reaches the bottom, it is immediately cemented so a lot of time is saved. Also viper trip time is saved. Actually, major saving is in the time because plastering effect is known to reduce the loss circulations and time needed to cure those loss circulations.

6.6.3 Case 2: Slim-bore Case

Final summary of slim bore case is given below in *Table 28*. Only extra cost in this case is “casing drilling” and “liner drilling” costs. Lot of time is saved due to lean wellbore design which in turn saves cost. Approx. 540m of casing drilling and 340m of liner drilling is done in two separate sections. It saves USD 1.01 million as compared to conventional case. Total time is saved by 4.7 days but total cost saved is much higher due to lean well bore design.

Table 28: Miano well cost summary (Slim-bore case)

Miano NN WELL: TD 3550 m TVD/MD	
Cost Categories	**Million USD**
Location costs	$0.60
Total Costs for Rig, Rig Move, Fuel and Water supply	$1.78
Water based drilling fluid mud incl. Solid control	$0.29
Tubulars (Casings: 9-5/8”,7”& 4-1/2”)	$0.69
Well heads X-tree	$0.34
Bit and Downhole Tools	$0.20
Cementing	$0.18
Fishing and rentals	$0.09
Directional services	$0.00
Liner hanger	$0.13
Logging and formation evaluation incl. CBL, VDL, coring	$0.58
Completions and CIT	$0.94
Miscellaneous	$0.65
Extra cost due to Casing Drilling & Liner Drilling	$0.12
Total cost of the well without contingency	$6.57
Total cost with 5% contingency	**$6.90**
Days in total	34 days

ROP for drilling is predicted from Miano 19. Miano-19 is a latest offset well. ROP data is extracted from ProNova software. The ROP’s for prognostic well with casing drilling application at two different depths are assumed and are used to make Time vs Depth curve in Microsoft excel. The assumed ROP are shown in *Table 29.*

Table 29: Offset and prognosis well ROP (Slim-bore case)

Hole Size	Miano-19(offset well)		Prognosis well	
	Drilled Depth (m)	Av. ROP(m/hr)	Hole Depth selected	ROP assumed
12.25"	60-1000	25.8	60-1000	24
9-5/8" CD			1000-1500	15
8.5"	1000-2300	17.7	1500-2260	15
7" LD			2260-2600	12
6"	2300-3550	12.6	2600-3550	10

Planning the time required for drilling a well is based on number of operations. All operations are assigned time; keeping in view the past experience, company policies and standard oil field practices. Casing & Liner drilling in slim bore case saves some time as compared to conventional drilling. Excel sheet was made with time allocation to every step involved in well construction. Phase wise time breakdown is shown in Table *30*.

Table 30: Time Breakdown (Slim bore case)

Miano-NN Slim hole case			
Operation	**Section time**	**Depth**	**Cum. Time**
	Days	m	Days
Spud	0	0	0
Drill 13 3/8" hole section	4	1000	4
Run 9 5/8" CSG	1	1500	6
Drill 8" Hole	5	2262	10
Run 7" liner	1	2600	11
Drill 6" hole	3	3361	14
Drill 6" hole to well TD	1	3550	15
Wiper trip	1	3550	16
Logging	3	3550	19
Run 4 1/2" LINER	3	3550	22
Completion	10	3550	32
Contingency 10% on Drilling	2	3550	34
Total			**34**

Summary of time statistics for the wellbore is shown in *Table 31*. Time for drilling a well, logging, last liner run and completions time along with 10% contingency on drilling time plus one extra day.

Table 31: Time summary of slim-bore case

Well statistics	**Time**
Time (Dryhole)	16 days
Time (7" Liner)	3 days
Logging	3 days
Completion	10 days
Contingency 10%	2 days
Time on Well	34 days

Time vs depth of casing drilling case is shown in *Figure 66*. *Table 32* shows different phases of slim-bore case. Green line shows time vs drilled depth while red line shows time vs bit position. There is one casing drilling section and one liner drilling section. Section-1 is from 1000-1500m and section-2 is from 2262-2600m and is casing and liner drilling sections respectively. All the other sections are drilled conventionally. All the drilling operations between casing drilling case, conventional drilling case and slim bore case are logically the same including wiper trips. Operations after 7” liner cementing and all the following events and their corresponding times are exactly the same. Casing points are kept at 1500m and 2600m depth and can be seen from flat spots. There is a contingent wiper trip at 1000m, 1500m and 2300m.

One casing point at 1500m and two liner points at 2600m and 3550m TD is selected. Major difference between slim-bore case and all the other cases is due to improved ROP in smaller holes. Pipe handling time is also reduced (takes less time) because of smaller diameter pipes. Liner drilling section also saves lot of time. This is due to reduction in pipe tripping time and small diameter pipes which results in faster running in hole.

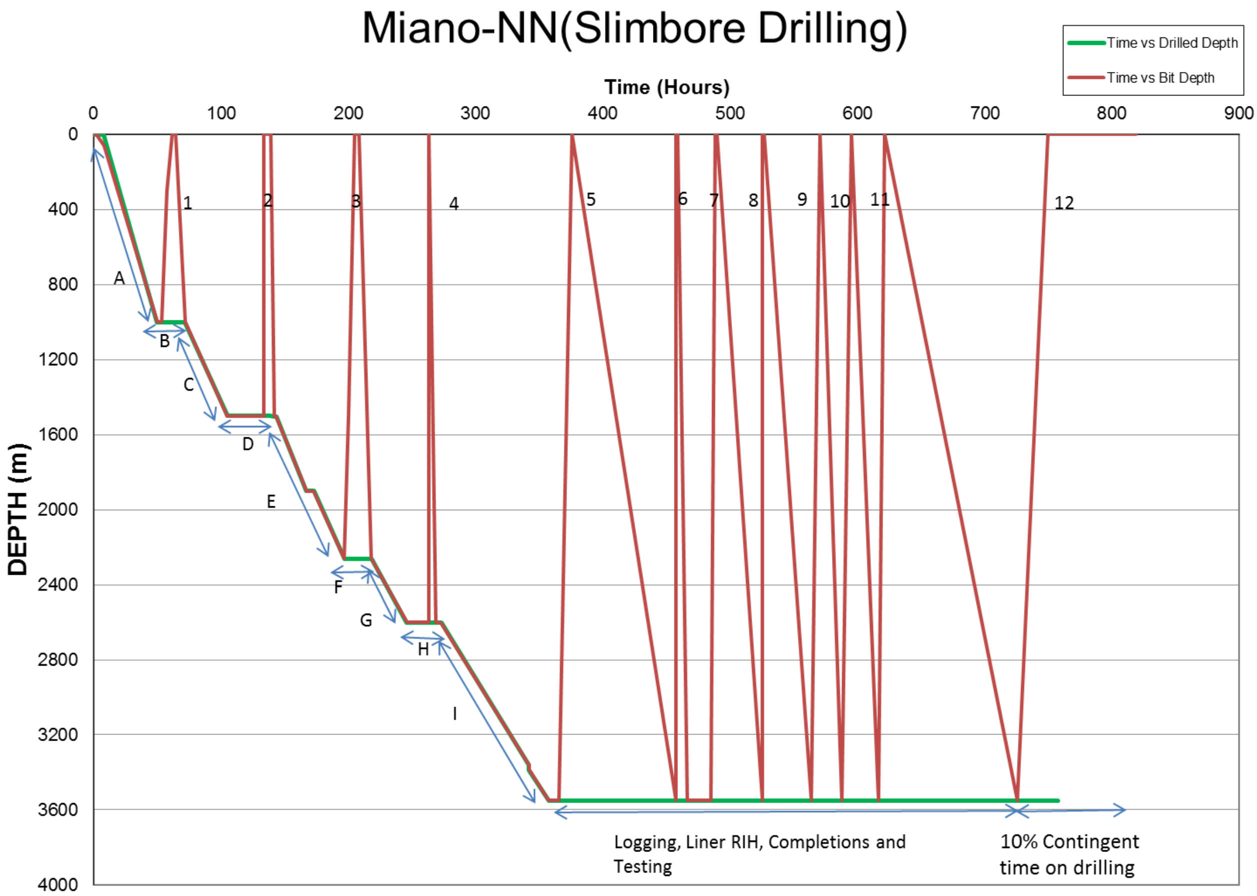

Figure 66: TVD ("Miano NN" Slim-bore Case)

Table 32: Different phases of slim-bore well

Phase	Operation	Tripping	Operation
A	Drill 12-1/4" section	1	RIH Casing with bit
B	Flat time	2	RIH DP TOC
C	Drill with casing	3	Formation Evaluation
D	Flat time	4	RIH Drill pipe
E	Drill 8-1/2" section	5	Wire line logging
F	Flat time	6	4-1/2" Liner job
G	Drill with liner	7	Liner Cleanout
H	Flat time	8	RIH 3.5" completions
I	Drill 6" section	9	Slick line
		10	Coil tubing
		11	Wireline
		12	Final POOH

6.6.4 Key performance indicators (KPI)

Following KPI's are used for pipe running inside the wellbore for all the cases. RIH of stands per hour of time is given in *Table 33*. Number of meters assumed for each strand or string is also given. These are based on the general operational practices and the efficiency of rig crew. KPI are based on average pipe moving data from Miano 19, Latif South-1 and Latif 14.

Table 33: KPI’s

KPI (stands/hr)		
	OH	CH
DP (30m)	16	20
BHA (9m)	6	6
Casing 13-3/8” (11m)	11	11
Casing 9-5/8” (11m)	13	13
Liner 7” (11m)	15	15
Liner 4-1/2” (11m)	15	15

6.6.5 Comparison of Cost and Time vs Depth (all cases)

Cost category for each individual operation along with their costs is given in *Table 34*. Total days are also given. There is a considerable difference in time and cost in all the 3 scenarios. Most attracting difference in cost and time lies between conventional case and slim-bore case. Total difference of time is around 4.7 days along with a cost saving of more than a million dollar.

Table 34: Cost and days chart (All cases)

Miano NN WELL: TD 3550 m TVD/MD			
Cost Categories	USD in million (conv BHA case)	USD in million (CD case)	USD in million (Slim bore case)
Location costs	$0.60	$0.60	$0.60
Total costs for rig, fuel & water	$1.94	$1.85	$1.78
Drilling fluid mud incl. Solid control	$0.52	$0.45	$0.29
Tubulars (casings & Liners)	$1.13	$1.13	$0.69
Well heads x-tree	$0.38	$0.38	$0.34
Bit and downhole tools	$0.33	$0.24	$0.20
Cementing	$0.27	$0.27	$0.18
Fishing and rentals	$0.10	$0.10	$0.09
Directional services	$0.00	$0.00	$0.00
Liner hanger	$0.07	$0.07	$0.13
Logging & Coring	$0.54	$0.54	$0.58
Completions and CIT	$0.94	$0.94	$0.94
Miscellaneous	$0.72	$0.68	$0.65
Extra cost due to casing drilling	$0.00	$0.12	$0.12
TOTAL COST OF THE WELL W/O CONTINGENCY	$7.53	$7.36	$6.57
TOTAL COST WITH 5% CONTINGENCY	$7.91	$7.73	$6.90
DAYS IN TOTAL	38.7 days	36.1 days	34.0 days

Time vs depth graphs from DWOP is shown to compare the results from all the three cases. Blue line shows the conventional case, green being the casing drilling and red line shows slim-bore case. All the operational sequences are the same. For last section, time and slops are exactly the same. Slim bore takes least time vs depth due to its lean geometry. This is shown in *Figure 67.*

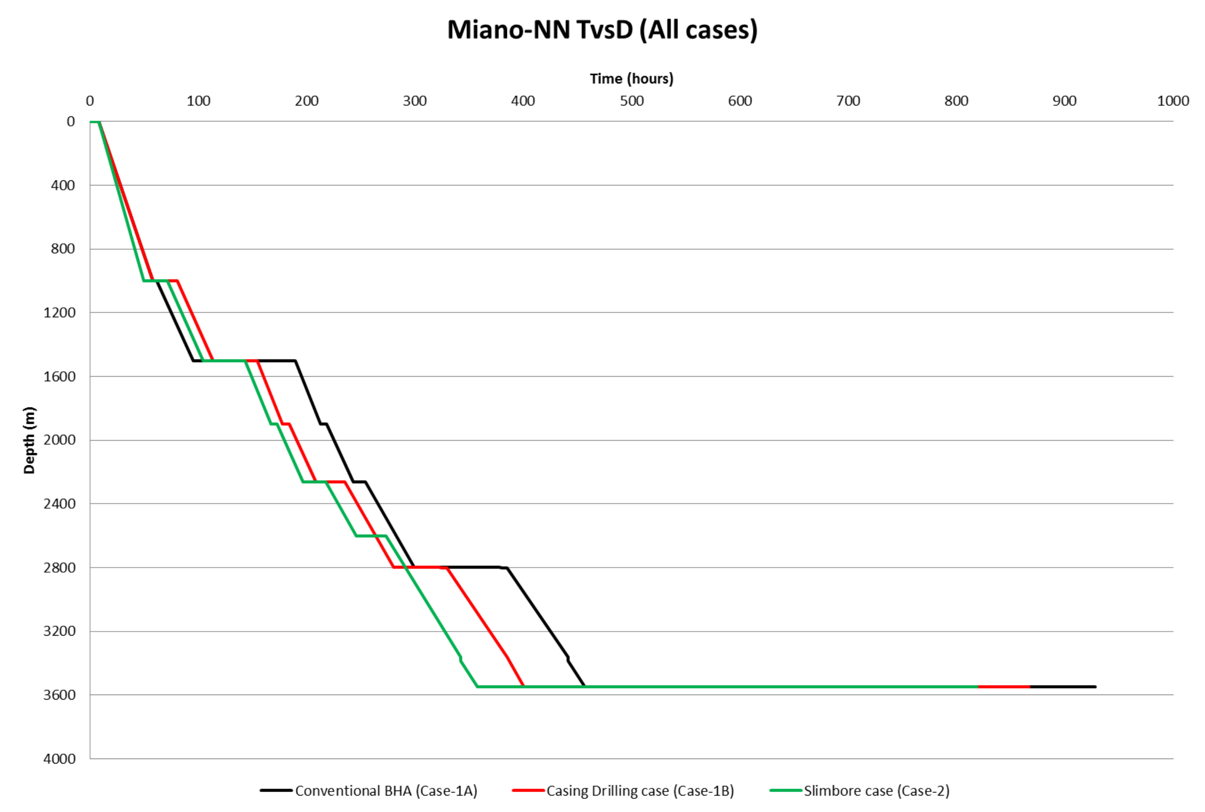

Figure 67: Time vs Depth (All cases)

6.6.6 Cost and Days comparison (all cases)

Cost and days comparison for all the cases is shown below in bar chart in *Figure 68* and in graph in *Figure 69*. Conventional days show highest cost and highest time followed by Casing drilling. Slim-bore shows lowest time and lowest cost.

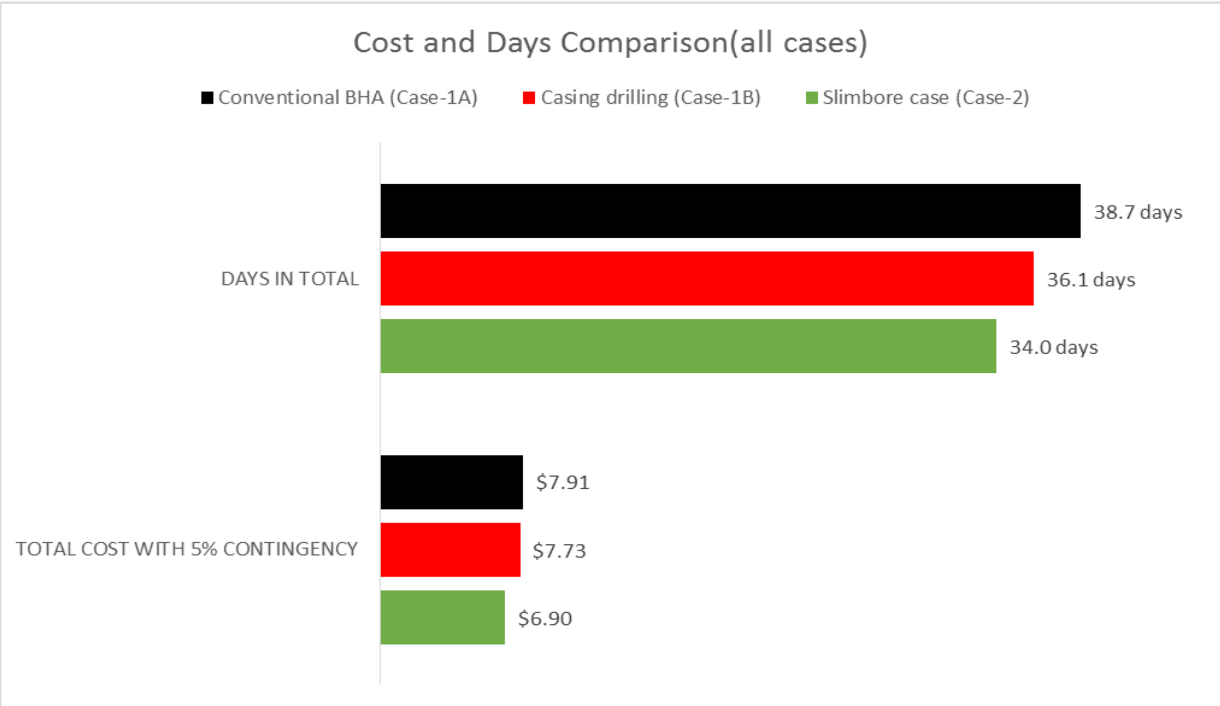

Figure 68: Cost and Days comparison bar chart (all cases)

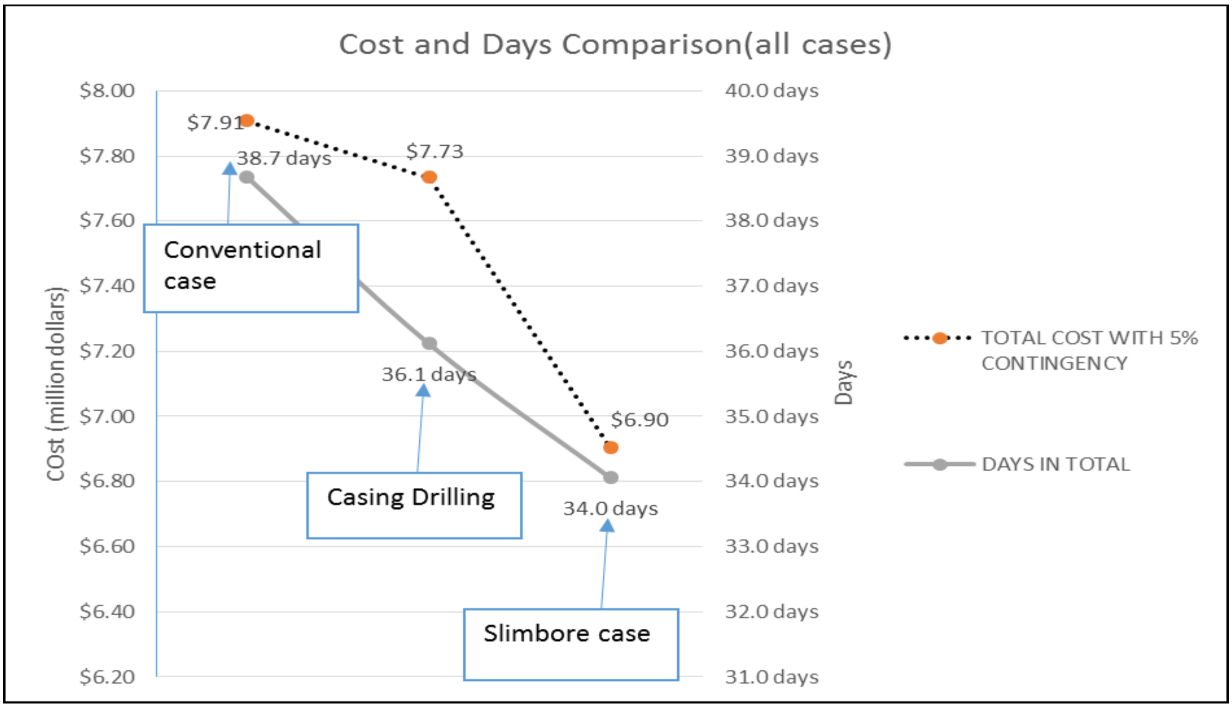

Figure 69: Cost and Days graph (all cases)

6.6.7 Major cost differences between all the cases

Major cost differences in particular operations are shown in *Table 35*. Only those operations are shown which have a cost saving of $10k and above. % difference is shown in the graphical and tabular form. Red colored cells shows higher costs compared to conventional design while blue colored cells show the savings. Graph in *Figure 70* shows time and days correlation in all the three cases. Total savings for cost is around $1 million while total time saving is 4.7 days which will be a significant success if achieved.

Table 35: % Cost difference: Conventional-Casing drilling case, Conventional-Slimbore case

	USD in million				
Categories	**Conv. BHA (Case-1A)**	**Casing drilling (Case-1B)**	**Slim bore (Case-2)**	**% Diff. of Case-1B from Case-1A**	**% Diff. of Case-2 from Case-1A**
	Values			**Savings**	
Tubulars (casings & Liners)	$1.13	$1.13	$0.69	$ -	$ 0.44
Drilling fluid mud incl. Solid control	$0.52	$0.45	$0.29	$ 0.07	$ 0.23
Total costs for rig, fuel & water	$1.94	$1.85	$1.78	$ 0.09	$ 0.16
Bit and downhole tools	$0.33	$0.24	$0.20	$ 0.09	$ 0.13
Cementing	$0.27	$0.27	$0.18	$ -	$ 0.09
Miscellaneous	$0.72	$0.68	$0.65	$ 0.04	$ 0.07
Well heads x-tree	$0.38	$0.38	$0.34	$ -	$ 0.04
Fishing and rentals	$0.10	$0.10	$0.09	$ -	$ 0.01
Logging & Coring	$0.54	$0.54	$0.58	$ -	$ (0.04)
Liner hanger	$0.07	$0.07	$0.13	$ (0.01)	$ (0.06)
Extra cost due to casing drilling	$0.00	$0.12	$0.12	$ (0.12)	$ (0.12)
Other Costs	$1.92	$1.90	$1.90	$ 0.02	$ 0.02
Total costs (with 5% contingency)	$7.91	$7.73	$6.90	$ 0.18	$ 1.01
Days	38.7 days	36.1 days	34.0 days	2.60 days	4.70 days

Major cost difference lies between conventional and slim bore case. So, bar chart showing cost difference is shown in bar-chart. Major saving potential lies in tubular and drilling fluid costs. This is shown in *Figure 70.*

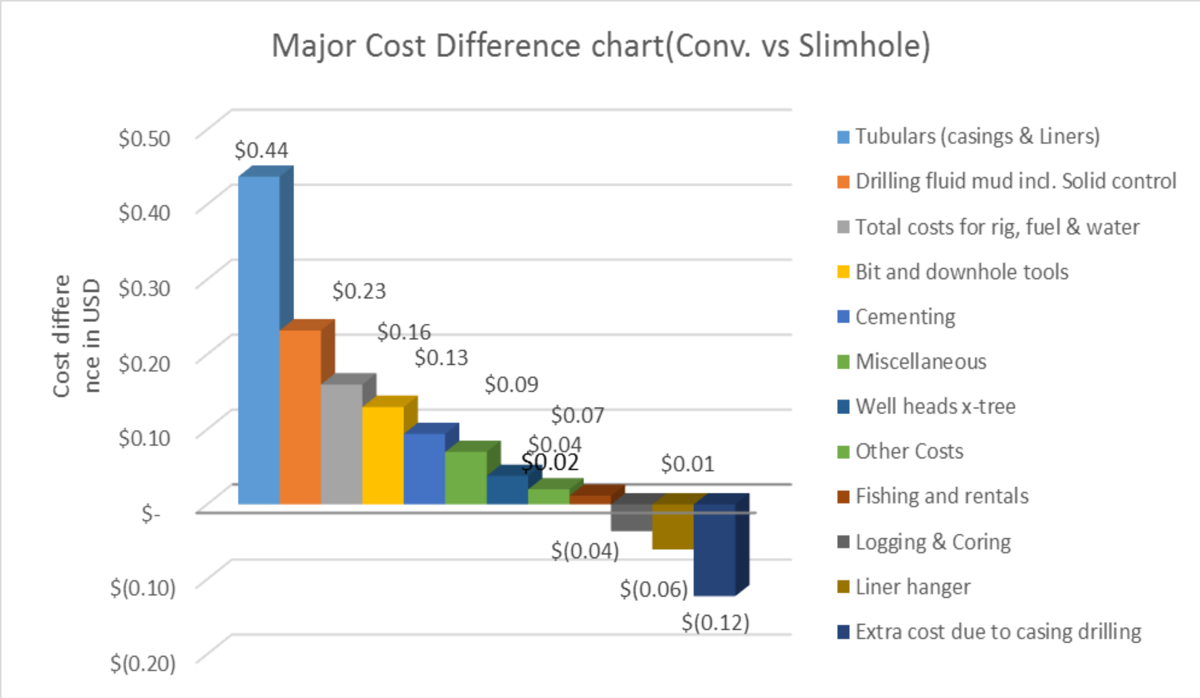

Figure 70: Major Cost Difference

7.0 Conclusion

Following conclusions can be made from the feasibility study of casing drilling technology in OMV, Pakistan Operations. Casing drilling is highly recommended for OMV, Pakistan section. Main advantage of using casing drilling is for the purpose of drilling Ghazij and SML formations. Conclusions are described below:

- Casing drilling can reduce the contingency which prevails due to problematic zones in our drilling path.
- Higher quality wellbores are expected with Casing drilling which means reduced chances of losing BHA or bit downhole (in retrievable BHA).
- Availability of casing drilling equipment and expertise is not a problem as it is provided by a services company within country.
- Slim-bore design coupled with casing and liner drilling promises a great saving potential both in terms of time and money.
- Even if (due to current market situation) companies do not like to imply this technique, slim-bore design itself can prove to be of much worth.
- Timesaving & increase in revenues generated due to early production.

Some of the general positive points of casing drilling are given below:

- Casing and liner drilling helps in flat time reduction and problem resolution.
- Reduce risk and mitigate hole problems.
- CD is very effective for wells having well instability problems.
- CD technology can be effectively employed with continuous drilling and improved technical knowledge.
- Higher quality wellbores are expected with CD.
- Reduce equipment rentals.
- Reduce hydraulic requirements.
- Better borehole quality.
- Allows cement to be done immediately upon reaching TD.
- Well construction is simplified.
- Plastering effect is the main cause of mechanical stability.

7.1 Recommendations

- Avoid using centralizers – as preferred by OMV Pakistan.
- Try to keep the trajectory as vertical as possible and avoid having tortuosity, so that minimum friction could be encountered during the casing drilling.
- Do not exceed recommended WOB given by the service company in order to keep bit undamaged until cementation.

- Measure the hole before deploying casing drilling, if hole is inclined or has high DLS, the hole could not be fit for the casing drilling.

7.2 Limitations

Major concerns which limit the confidence of the partner companies using this technique is:

- The risk of drilling through hard / unknown inter-bedded formations (e.g. un-expected Cherts).
- Chances of stuck casing in SML formation.
- Formation hardness’s and depths for all of the formations are known but due to compartmentalization unexpected fractures and fault may intersect the wellbores.
- There is a bad experience of using casing drive tool during RIH of casing (due to leakage in hoses).
- Reaching the section TD is also a major point of concern among the partner companies.

7.3 Mitigation measures

Necessary mitigation measures need to be planned:

- Casing drilling can be employed after the Chert section is gone and there are no more chances for it to appear again.
- Major importance of using CD is to close the fractures due to plastering effect. So, there are no chances of stuck pipe in SML.
- Even if the fractures come in our path way during drilling. CD technique can close/minimize the effect of those fractures (much faster than conventional BHA).
- Formation hardness needs to be known so that proper bit can be selected for the job.
- Hoses and all the other equipment can be checked before commencing a job and spare parts can be made available on location.
- In casing drilling there are better chances of reaching section TD if things are planned accordingly. Only chances of not reaching TD can be due to bit and nozzle failures.

7.4 Future work

Retrievable multi-set Liner drilling technology will be an interesting area to research on. It would be great it some one finds the applicability of liner drilling while rotating DP only (which will be within the Liner).

Casing drilling with conventional retrievable system could be a point of interest for a feasibility report. Bit release mechanism which allows for logging of the formations even in non-retrievable systems is recommended for study.

Nomenclature

BHA	Bottom Hole Assembly
CD	Casing Drilling^{TM} (Tesco Corp.)
CDS	Casing Drive System
CDS	Casing Drive System
CH	Cased Hole
CR	Casing Running
DefyerTM	Weatherford casing drilling bits
DLA	Drill lock assembly
DLS	Dog leg severity
DP	Drill Pipe
DwCTM	Drilling With Casing^{TM} (Weatherford)
DWOP	Drilling well on paper
ECD	Equivalent Circulating Density
EMW	Equivalent mud weight
GOM	Gulf of Mexico
HWDP	Heavy weight drill pipe
ID	Inside diameter
LCM	Lost Circulation Material
LD	Liner Drilling
LWD	Logging while drilling
MD	Measured Depth
MWD	Measurement while drilling
NPT	Non-Productive Time
NPT	Non-Productive Time
OD	Outer Diameter
OH	Open Hole
PDC	Polycrystalline Diamond Compact
PSD	Particle Size Distribution
PV	Plastic viscosity
RIH	Running in hole
RSS	Rotary steerable system

ROP	Rate of penetration
S.F	Safety factors
SML	Sui main limestone
SPP	Stand pipe pressure
T & D	Torque and Drag
TD	Total Depth
TFA	Total flow area
TOC	Top of cement
TVD	True Vertical Depth
US	United States
VME	Von Mises Equation
YP	Yield point

Units

Ksi	Kilo psi
Bbl	barrel
Cp	centipoise
ft/sec	Foot per second
gpm	Gallons per minute
HHP	Hydraulic horse power
hp	Horse power
HSI	Hydraulic horsepower per square inch
lbf	Pound force
m/hr	Meter per hour
ppg	Pounds per gallon
psi	Pounds per square inch
RPM	Revolution per minute
Sq. in	Square inch

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Appendix A

Defyer™ DPA (Drillshoe 3 type) Series equipment specification

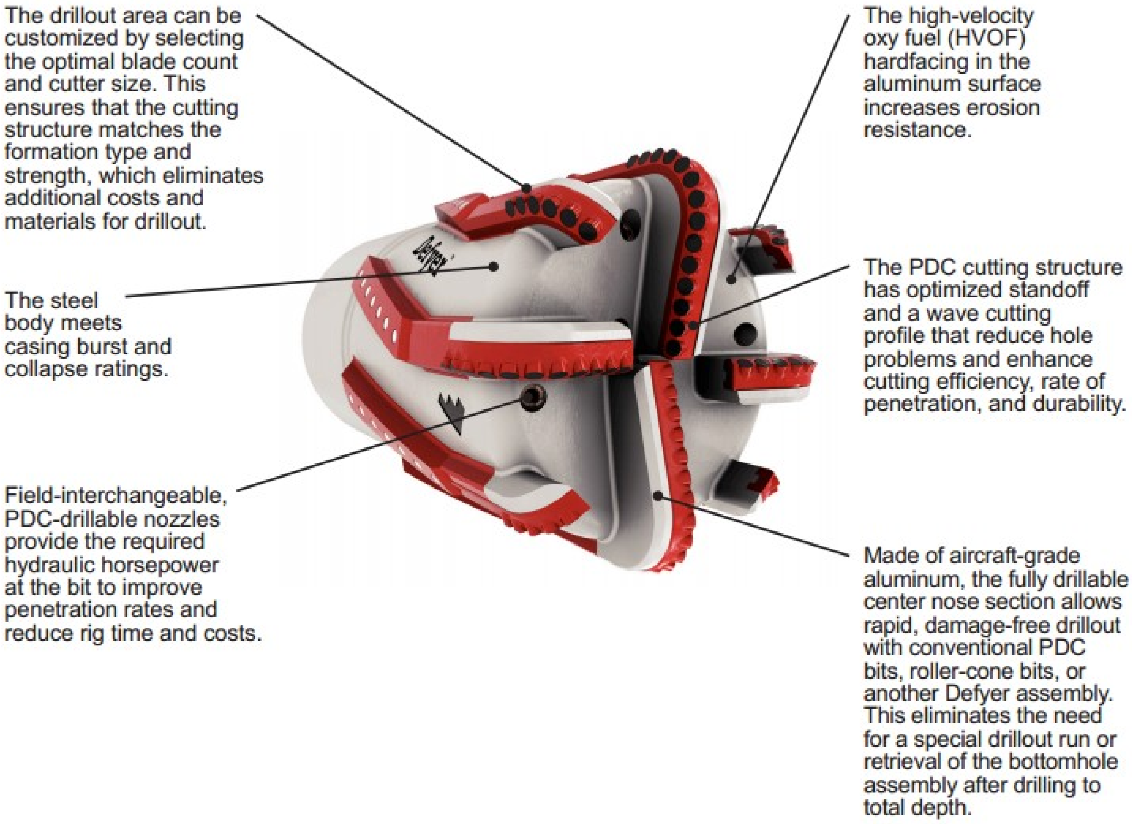


Figure 71: WFD DPA bit features

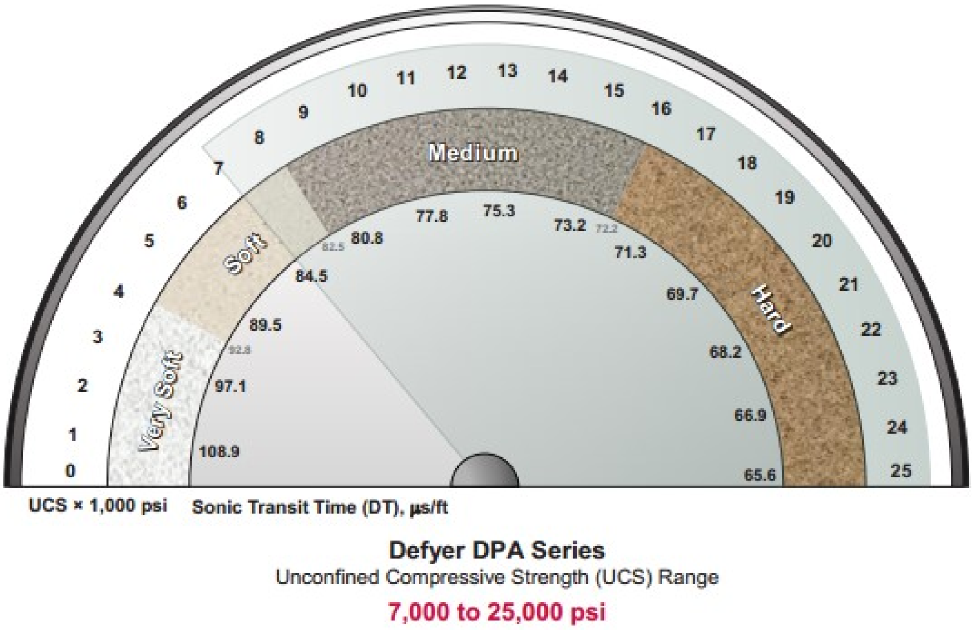


Figure 72: WFD DPA UCS Range

Overdrive system used for casing running.

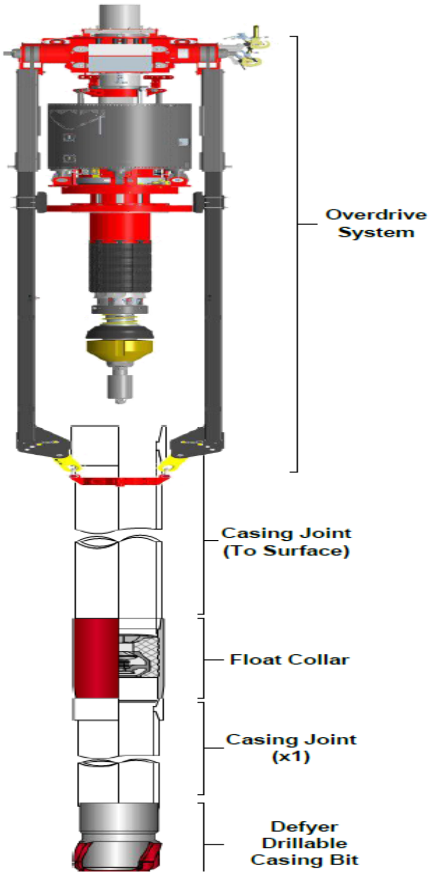


Figure 73:Generic String Configuration

TorkDrive DT Tool	External (DTE)	Internal (DTI)
Pipe sizes (in., *mm*)	**3-1/2 to 9-5/8** ***88.9 to 244.5***	**9-5/8 to 14** ***244.5 to 355.6***
Rated load[a] (tons, *kg*)	300 *272,155*	
Maximum makeup torque capability (ft-lb, *N•m*)[b]	30,000 to 40,000 *40,678 to 54,233*	
Connection to top drive[c]	NC-50, 6 5/8-in. Reg	
Design standard	API 8C PSL1	
Push-down capacity (tons, *kg*)	40 *36,287*	
Maximum rotating speed (rpm)	100	
Approximate weight, including housing with bails (lb, *kg*)	4,630 *2,100*	3,968 *1,800*
Maximum circulating pressure (psi, *bar*)	3,625 *250*	5,000 *345*
Operational temperature range (°F, °C)	–40° to 122° *–40° to 50°*	
Maximum flow (gal/min, *L/m*)	526 *1,990*	1,270 *4,808*

Figure 74: Specification of DTE and DTI

Drilling Formulas

Cost per Foot (CPF)

$$CPF = \frac{\text{Bit Cost} + \text{Rig Cost (Trip Time + Drilling Time)}}{\text{Footage Drilled}}$$

Pressure Drop (ΔD)

$$\Delta P = \frac{\text{Flow Rate}^2 \times \text{Mud Weight}}{10{,}856 \times TFA^2}$$

Hydraulic Horsepower (HHP)

$$HHP = \frac{\text{(Bit Pressure Drop) (Flow Rate)}}{1{,}714}$$

Hole Area (A_h)

$$A_h = \frac{\pi \times \text{Hole Diameter}^2}{4}$$

Hydraulic HP per Square Inch (HSI)

$$HSI = \frac{\text{Hydraulic Horsepower}}{\text{Hole Area, in}^2}$$

Flow Rate (Q)	= (Pump Stks × Output / stk)
Bit Pres. Drop (ΔP_{bit})	= (MWt. × Q^2) / (10858 × TFA^2)
Hydraulic Horsepower (HHP_{bit})	= (ΔP_{bit} × Q) / (1714)
HSI	= (HHP_{bit}) / (.7854 × D^2)
Jet Velocity (JV)	= (.32086 × Q) / (TFA)
Impact Force (IF)	= (JV) × (MWt) × (Q) × (.000516)

MWt = Mud Weight TFA = Nozzle Flow Area D = Bit Diameter

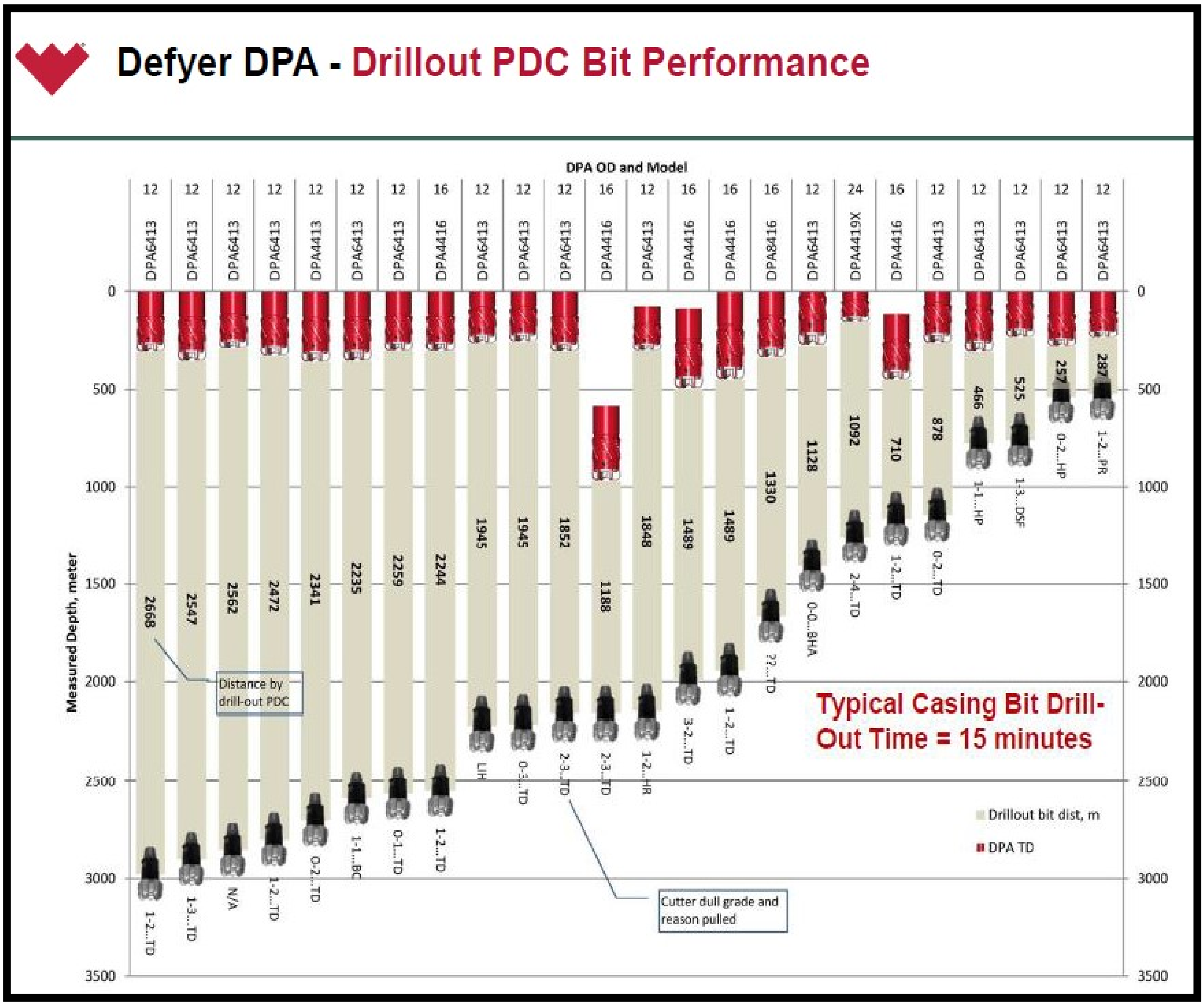


Figure 75: Proved Performances of Drill out PDC [10]

Specifications DPA Bits

Nominal size (in.)	**9-5/8 × 12**	**9-7/8 × 12**	**10-3/4 × 13-1/2**	**10-3/4 × 13-1/2**
Defyer code	DPA4416X			DPA5416X
Casing size (in.)	9-5/8	9-7/8	10-3/4	
Casing weight range (lbf/ft, *kg/m*)	36.0 to 53.5 *53.6 to 79.6*	62.8 to 66.9 *93.5 to 99.6*	51.0 to 60.7 *75.9 to 90.0*	
Connection	As requested			
OD (in., *mm*)	12 *304.8*		13-1/2 *342.9*	
ID below casing connection (in., *mm*)	8.799 to 8.515 *223.50 to 216.29*	8.515 *216.29*	Drift diameter + 1.5 mm	
Drillout diameter (in., *mm*)	8.500 *217.00*	8.750 *223.50*	9.50 *241.30*	
Drift diameter	To API 5CT			
Tool length (ft, *m*)	26.43 *671.4*		30.11 *765.0*	
Fishing neck length (in., *mm*)	10.04 *255.0*		9.88 *251.0*	
Tool weight (lb, *kg*)	240 *109*		650 *295*	661 *300*
IADC code	S123		S123	S223
Number of blades	4		4	5
Number of blades inside drillout diameter	4		4	4
Number of nozzles	6		6	7
Nozzle type	Type 100 and 200			
Number of primary face cutters	27		33	37
Primary face cutter size (in., *mm*)	0.63 (23), 0.53 (4) *15.9, 13.4*		0.53 (6), 0.63 (27) *13.4, 15.9*	0.53 (6), 0.63 (31) *13.4, 15.9*
Number of cutters inside drillout diameter	14		19	
Cutter size inside drillout diameter (in., *mm*)	0.63 (10), 0.53 (4) *15.9, 13.4*		0.53 (6), 0.63 (13) *13.4, 15.9*	
Gauge length (in., *mm*)	7.05 *179.1*		9.04 *229.7*	9.09 *230.8*
Gauge protection	Serrated carbide inserts		Serrated carbide inserts	
Gauge cutter size (in., *mm*)	0.63 *15.9*			
Number of gauge cutters	8		8	10
Face protection	HVOF hardfacing			
Total flow area	Dependent on nozzle selection			
Junk slot area (in.^{2}, *cm*^{2})	20.7 *133.0*		19.1 *123.0*	19.4 *125.0*
Equivalent casing grade (ksi, *MPa*)	110 *758*			
Burst (psi, *MPa*)	11,250 *77.60*		9,760 *67.29*	9,610 *66.26*
Collapse (psi, *MPa*)	10,220 *70.50*		8,200 *56.53*	8,240 *56.81*
Nose material	Drillable aluminum alloy			

Nominal size (in.)	13-3/8 × 16	13-3/8 × 16	13-3/8 ×16	13-3/8 × 16	13-3/8 × 17	13-3/8 × 17
Defyer code	DPA4416	DPA8416	DPA8413	DPA4413	DPA8516X	DPA4419X
Casing size (in.)	13-3/8					
Casing weight range (lbf/ft, *kg/m*)	54.5 to 72.0 *81.1 to 107.1*				61.0 to 72.0 *90.8 to 107.1*	
Connection	As requested					
OD (in., *mm*)	16 *406.4*				17 *431.8*	
ID below casing connection (in., *mm*)	Drift diameter + 1.5 mm					
Drillout diameter (in., *mm*)	12.250 *311.15*					
Drift diameter	To API 5CT					
Tool length (in) mm	29.54 *750.4*					30.55 *776.1*
Fishing neck length (in., *mm*)	10.04 *255.0*				9.84 *250.0*	
Tool weight (lb, *kg*)	275 *125*	305 *139*		275 *125*	320 *145*	300 *136*
IADC code	S123	S223	S233	S133	S223	S123
Number of blades	4	8		4	8	4
Number of blades inside drillout diameter	4				5	4
Number of nozzles	6					
Nozzle type	Type 100 and 200					
Number of primary face cutters	40	55	63	45	64	35
Primary face cutter size (in., *mm*)	0.63 *15.9*		0.53 *13.4*		0.63 (58), 0.53 (6) *15.9, 13.4*	0.75 (29), 0.63 (6) *19.1, 15.9*
Number of cutters inside drillout diameter	24		27		28	21
Cutter size inside drillout diameter (in., *mm*)	0.63 *15.9*		0.53 *13.4*	0.53 *13.4*	0.63 (22), 0.53 (6) *15.9, 13.4*	0.63 (6), 0.75 (15) *15.9, 19.1*
Gauge length (in., *mm*)	8.86 *225.0*				8.34 *211.8*	
Gauge protection	Serrated carbide inserts					
Gauge cutter size (in., *mm*)	0.63 *15.9*		0.53 *13.4*		0.63 *15.9*	0.75 *19.1*
Number of gauge cutters	8	16		8	16	8
Face protection	HVOF hardfacing					
Total flow area	Dependent on nozzle selection					
Junk slot area (in.^{2}, *cm^2*)	39.9 *257.6*	33.2 *214.0*		39.9 *257.6*	46.5 *300.0*	55.0 *354.7*
Equivalent casing grade (ksi, *MPa*)	80 *552*				110 *758*	
Burst (psi, *MPa*)	5,579 *38.50*				7,565 *52.16*	
Collapse (psi, *MPa*)	5,516 *36.00*				6,911 *47.65*	
Nose material	Drillable aluminum alloy					

Nominal size (in.)	7 × 8-1/2	7-5/8 × 8-1/2	7-5/8 × 8-1/2	7-5/8 × 8-1/2	7-5/8 × 9-7/8
Defyer code	DPA5513		DPA4416X	DPA8813X	DPA5513
Casing size (in.)	7	7-5/8			
Casing weight range (lbf/ft, *kg/m*)	20.0 to 32.0 *29.8 to 47.6*	33.7 to 39.0 *50.1 to 58.0*			29.7 to 39.0 *50.0 to 58.0*
Connection	As requested				
OD (in., *mm*)	8-1/2 *215.9*				9-7/8 *250.8*
ID below casing connection (in., *mm*)	Drift diameter + 1.0 mm				
Drillout diameter (in., *mm*)	6.000 *152.40*	6.500 *165.10*			
Drift diameter	To API 5CT				
Tool length (ft, *m*)	23.60 *600.0*	23.61 *599.6*	20.83 *529.0*		23.63 *600.3*
Fishing neck length (in., *mm*)	10.100 *253.00*	10.059 *255.50*	9.843 *250.00*		9.961 *253.00*
Tool weight (lb, *kg*)	137 *63*		120 *54*	137 *63*	
IADC code	S333		S222	S432	S333
Number of blades Number of blades inside drillout diameter	5		4	8	5
Number of nozzles	7		6		7
Nozzle type	Type 20 and 300		Type 300		Type 20 and 300
Number of primary face cutters	27		23	43	34
Primary face cutter size (in., *mm*)	0.53 *13.4*		0.63 (17), 0.53 (6) *15.9, 13.4*	0.53 (37), 0.35 (6) *13.4, 9.0*	0.53 *13.4*
Number of cutters inside drillout diameter	15	17	16	24	17
Cutter size inside drillout diameter (in., *mm*)	0.53 *13.4*		0.53 (6), 0.63 (10) *13.4, 15.9*	0.35 (6), 0.51 (18) *9.0, 13.0*	0.53 *13.4*
Gauge length (in., *mm*)	6.14 155.9	6.30 *159.9*	4.02 *102.0*		5.96 *151.3*
Gauge protection	Serrated carbide inserts				
Gauge cutter size (in., *mm*)	0.53 *13.4*		0.63 *15.9*	0.53 *13.4*	0.53 *13.4*
Number of gauge cutters	5	5	8	16	10
Face protection	HVOF hardfacing				
Total flow area	Dependent on nozzle selection				
Junk slot area (in.^{2}, *cm*^{2})	7.6 *49.1*	4.6 *29.5*	6.5 *41.8*		15.1 *97.7*
Equivalent casing grade (ksi, *MPa*)	110 *758*				
Burst (psi, *MPa*)	12,955 *89.00*	12,620 *87.01*	12,620 *87.01*		
Collapse (psi, *MPa*)	11,970 *83.00*	11,080 *76.39*	11,480 *79.15*		11,080 *76.39*
Nose material	Drillable aluminum alloy				

Operating Parameters

<table>
<tr><th>Nominal size (in.)</th><th>7 × 8-1/2</th><th>7-5/8 × 8-1/2</th><th>7-5/8 × 8-1/2</th><th>7-5/8 × 8-1/2</th><th>7-5/8 × 9-7/8</th></tr>
<tr><td>Defyer code</td><td colspan="2">DPA5513</td><td>DPA4416X</td><td>DPA8813X</td><td>DPA5513</td></tr>
<tr><td>Minimum rotary speed (rpm)</td><td colspan="5">50</td></tr>
<tr><td>Maximum rotary speed (rpm)</td><td colspan="5">200</td></tr>
<tr><td>Minimum WOB (lb, kg)</td><td colspan="3">3,000
1,361</td><td>4,000
1,814</td><td>3,000
1,361</td></tr>
<tr><td>Maximum WOB (lb, kg)</td><td colspan="2">24,000
10,886</td><td>21,000
9,526</td><td>31,000
14,062</td><td>28,000
12,700</td></tr>
<tr><td>Minimum flow rate
(gal/min, L/min)</td><td>120
454</td><td colspan="3">75
284</td><td>200
757</td></tr>
<tr><td>Maximum flow rate
(gal/min, L/min)</td><td>240
908</td><td>140
530</td><td colspan="2">150
568</td><td>500
1,514</td></tr>
<tr><td>Minimum torque (ft-lb, N•m)</td><td colspan="4">1,000
1,356</td><td>1,200
1,627</td></tr>
<tr><td>Maximum torque (ft-lb, N•m)</td><td colspan="5">90% of maximum connection makeup torque</td></tr>
</table>

<table>
<tr><th>Nominal size (in.)</th><th>9-5/8 × 12</th><th>9-7/8 × 12</th><th>10-3/4 × 13-1/2</th><th>10-3/4 × 13-1/2</th></tr>
<tr><td>Defyer code</td><td colspan="3">DPA4416X</td><td>DPA5416X</td></tr>
<tr><td>Minimum rotary speed (rpm)</td><td colspan="2">40</td><td colspan="2">30</td></tr>
<tr><td>Maximum rotary speed (rpm)</td><td colspan="2">200</td><td colspan="2">200</td></tr>
<tr><td>Minimum WOB (lb, kg)</td><td colspan="3">3,000
1,361</td><td>4,000
1,814</td></tr>
<tr><td>Maximum WOB (lb, kg)</td><td colspan="2">25,000
11,340</td><td>30,000
13,608</td><td>33,000
14,969</td></tr>
<tr><td>Minimum flow rate
(gal/min, L/min)</td><td colspan="2">250
946</td><td colspan="2">350
1,325</td></tr>
<tr><td>Maximum flow rate
(gal/min, L/min)</td><td colspan="2">500
1,893</td><td colspan="2">650
2,461</td></tr>
<tr><td>Minimum torque (ft-lb, N•m)</td><td colspan="2">1,500
2,034</td><td colspan="2">2,000
2,712</td></tr>
<tr><td>Maximum torque (ft-lb, N•m)</td><td colspan="4">90% of maximum connection makeup torque</td></tr>
</table>

<table>
<tr><th>Nominal size (in.)</th><th>13-3/8 × 16</th><th>13-3/8 × 16</th><th>13-3/8 ×16</th><th>13-3/8 × 16</th><th>13-3/8 × 17</th><th>13-3/8 × 17</th></tr>
<tr><td>Defyer code</td><td>DPA4416</td><td>DPA8416</td><td>DPA8413</td><td>DPA4413</td><td>DPA8516X</td><td>DPA4419X</td></tr>
<tr><td>Minimum rotary speed (rpm)</td><td colspan="6">30</td></tr>
<tr><td>Maximum rotary speed (rpm)</td><td colspan="4">180</td><td colspan="2">170</td></tr>
<tr><td>Minimum WOB (lb, kg)</td><td>4,000
1,814</td><td colspan="2">6,000
2,721</td><td>4,000
1,814</td><td>6,000
2,721</td><td>5,000
2,270</td></tr>
<tr><td>Maximum WOB (lb, kg)</td><td>38,000
17,236</td><td>52,000
23,587</td><td>55,000
24,947</td><td>39,000
17,690</td><td>58,000
26,308</td><td>44,000
20,000</td></tr>
<tr><td>Minimum flow rate
(gal/min, L/min)</td><td colspan="4">400
1,514</td><td colspan="2">550
2,082</td></tr>
<tr><td>Maximum flow rate
(gal/min, L/min)</td><td colspan="4">800
3,028</td><td colspan="2">1,100
4,164</td></tr>
<tr><td>Minimum torque (ft-lb, N•m)</td><td colspan="4">3,000
4,067</td><td colspan="2">3,500
4,745</td></tr>
<tr><td>Maximum torque (ft-lb, N•m)</td><td colspan="6">90% of maximum connection makeup torque</td></tr>
</table>

Appendix B

IADC Code for PDC bits

IADC classification : PDC bits

A	B	C	D
Bit body	Formation type	Cutting structure	Bit profile.

A – Bit body

"M"	Matrix
"S"	Steel
"D"	Diamond

Example

M	Matrix
4	Medium
3	PDC 13mm
4	Long profile

B – Formation type / C – Cutting structure

	Formation type		Cutting structure
1	Very soft	2	PDC, 19mm
		3	PDC, 13mm
		4	PDC, 8mm
2	Soft	2	PDC, 19mm
		3	PDC, 13mm
		4	PDC, 8mm
3	Soft to medium	2	PDC, 19mm
		3	PDC, 13mm
		4	PDC, 8mm
4	Medium	2	PDC, 19mm
		3	PDC, 13mm
		4	PDC, 8mm
5	no code		
6	Medium hard	1	Natural diamond
		2	TSP
		3	Combination
7	Hard	1	Natural diamond
		2	TSP
		3	Combination
8	Extremely hard	1	Natural diamond
		4	Impregnated diamond

D – Bit profile

1	Short fishtail
2	Short profile
3	Medium profile
4	Long profile

Formation Categories	Compressive Strength (PSI)	PDC Bits [IADC]
Very Soft	< 4000	S / M 121
Soft & Sticky	4000 to 6000	S / M 121 / 131
Soft	6000 to 9000	S/M 221 / 223
Soft Medium	9000 to 11000	S/M 231 / 233
Medium	11000 to 14000	S/M 323
Medium Hard	14000 to 18000	M 332 / 333
Hard	18000 to 24000	M 422 / 423
Extremely hard	> 24000	M 422 / 423 / 433

Appendix C

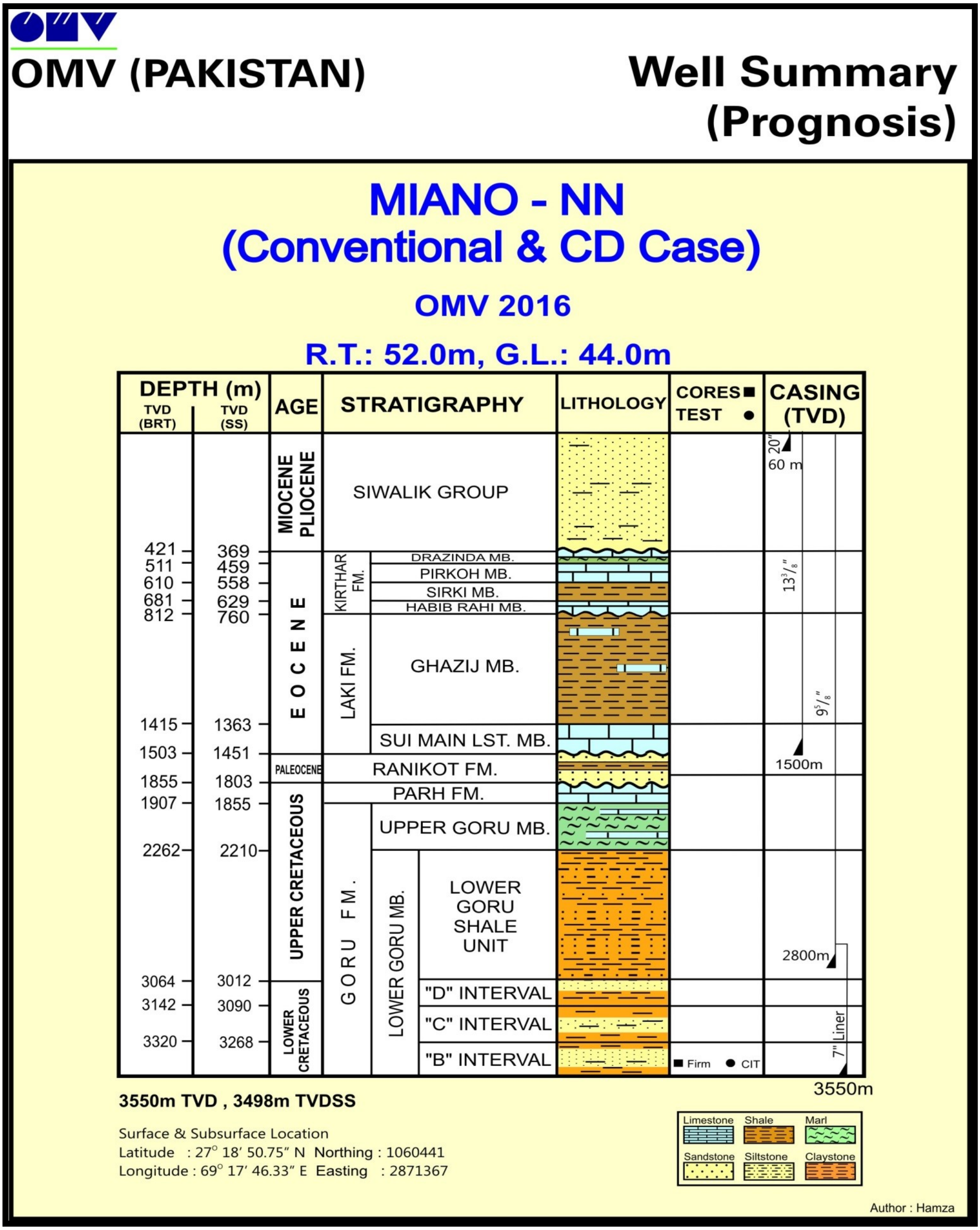


Figure 76: Well prognosis (Conventional and CD case)

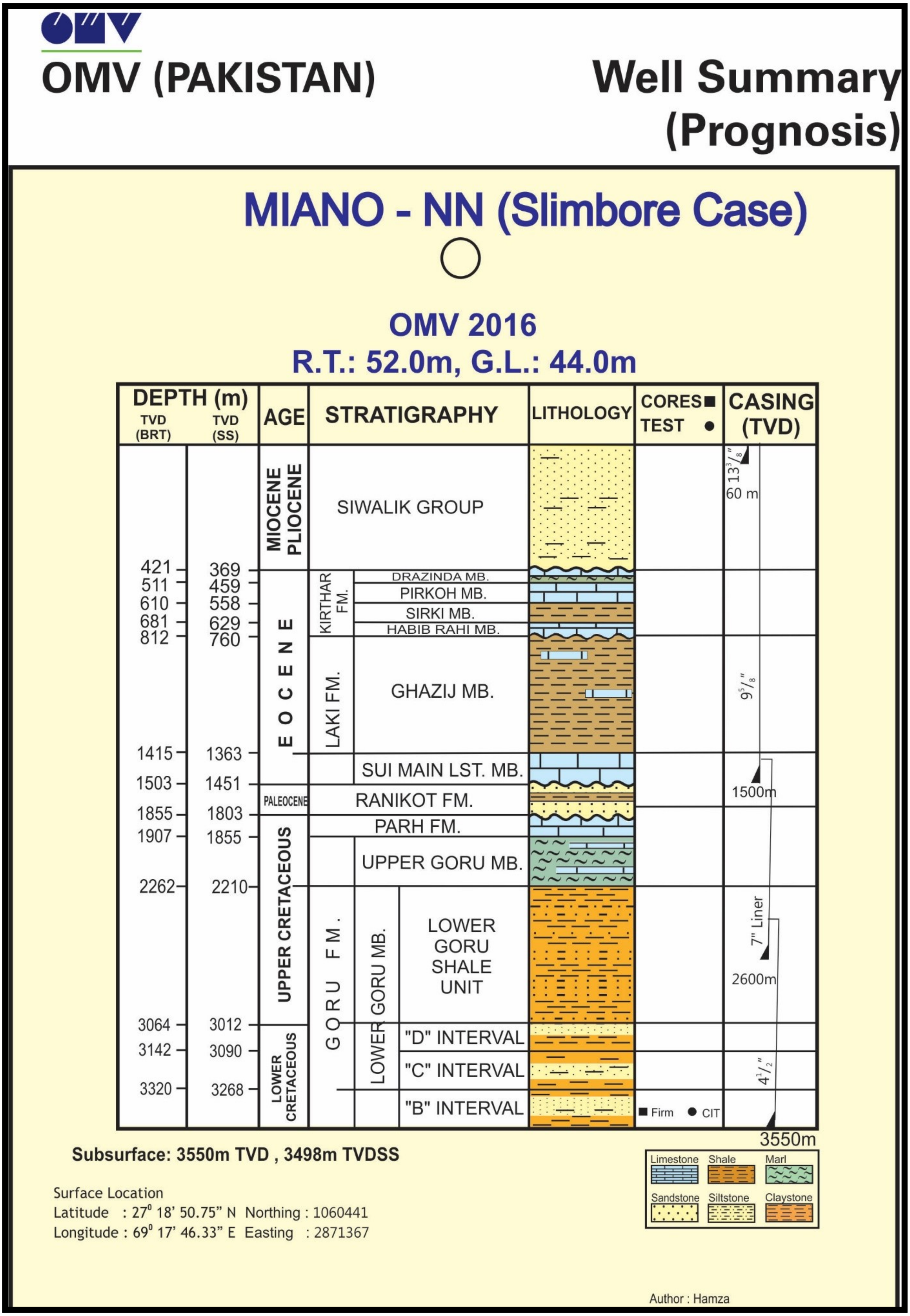


Figure 77: Well prognosis (Slim-bore Case)

Appendix D

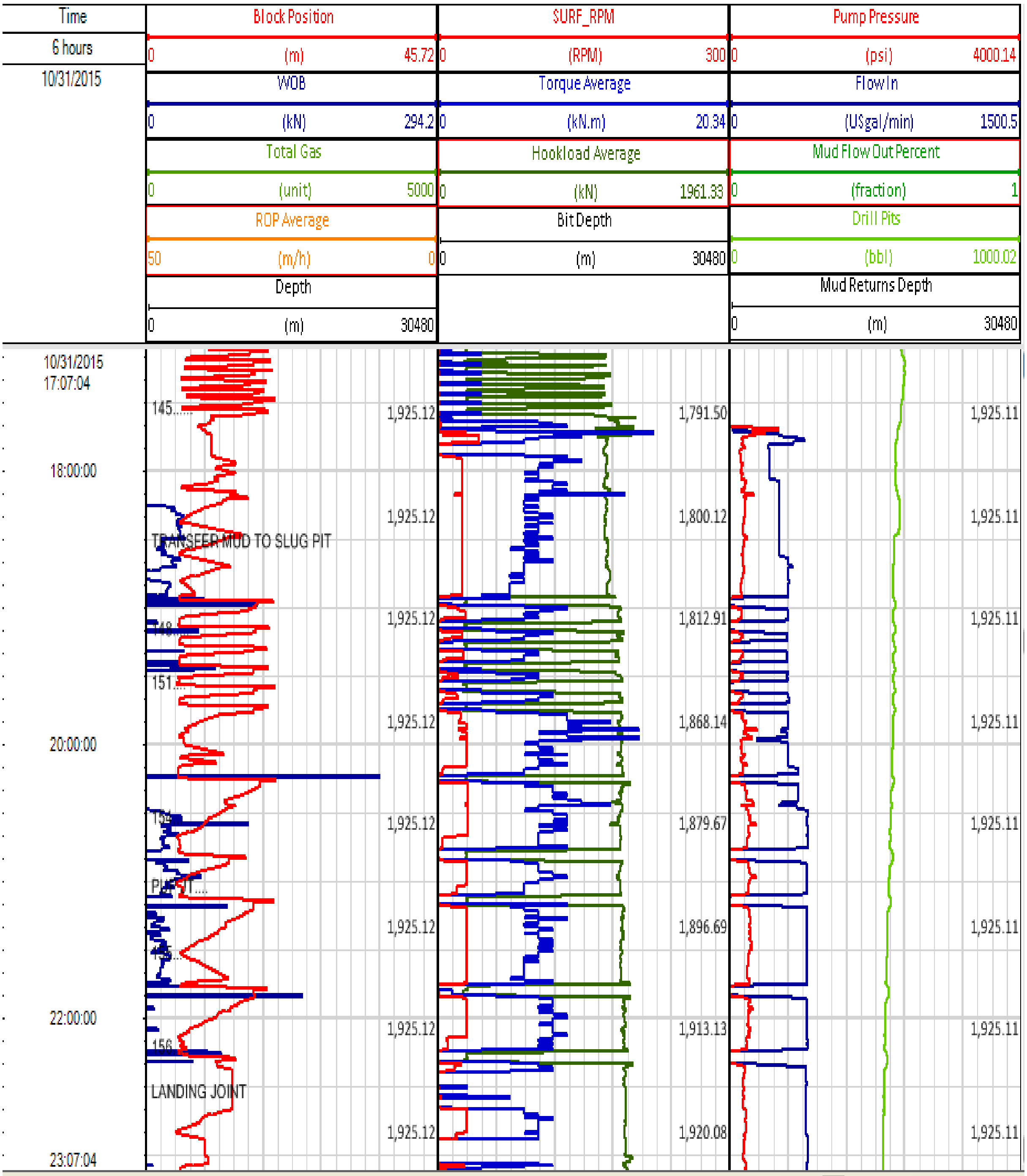


Figure 78: Reaming with casing (1790m-1920m)

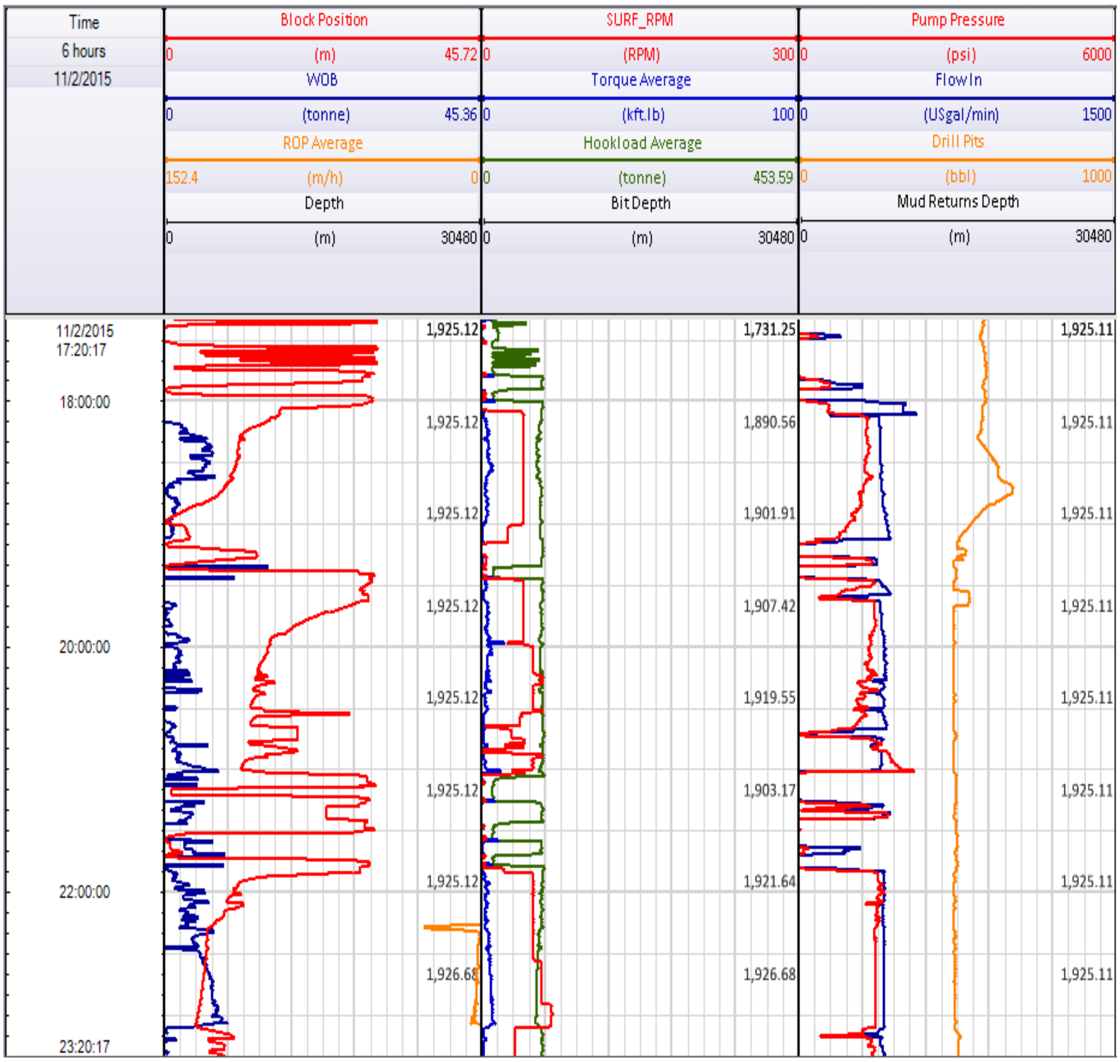
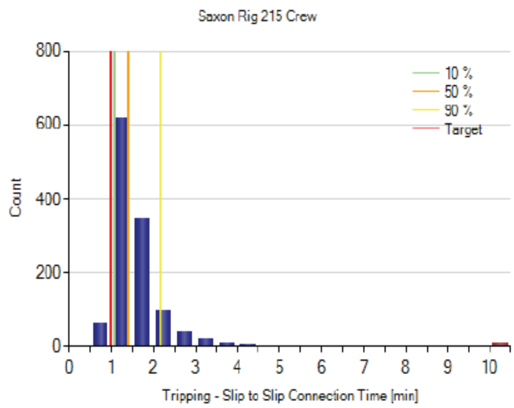


Figure 79: Drilling with casing (1790m-1920m)

Appendix E

Slip to slip connection time during drill pipe connections is shown below in Figure *80*. The target duration for slip to slip time is 1 minute. 50% of operations show it to be below 1.42 minutes.



Rig	Saxon Rig 215
Well	Miano-19
Lower / Upper Cutoff	0.20 / 10.00
Crew Name	Saxon Rig 215 Crew
Operation Count	1204
10%	1.08 min
50%	1.42 min
90%	2.17 min
Average	1.58 min
Deviation Avg	0.64 min
Deviation Target	0.87 min
Total Duration	1 d 7 h 48 min
Savings Potential	11 h 48 min
Savings Potential [%]	37.09%

Figure 80: Slip to slip connection time

Saving potential report of the tubular is shown below. There is a saving potential of 1.41 days (31.26%) out to 4.5 days in total.

KPI	Phase Diameter	Operation Count	Total Duration [h]	10%	50%	90%	Target [min]	Savings Potential [h]	Savings Potential [%]
Tripping - Slip to Slip Connection Time - CH	12.25"	57	1.94	1.49	1.88	2.82	1.00	0.99	50.92
	8.50"	728	18.04	1.05	1.33	1.97	1.00	5.97	33.07
Tripping - Pipe Moving Time - CH	12.25"	59	1.09	0.84	1.13	1.42	1.20	0.07	6.73
	8.50"	742	11.56	0.50	0.82	1.50	1.20	1.14	9.82
BHA - Slip to Slip Connection Time	17.50"	5	0.71	7.86	8.30	9.16	9.00	0.00	0.67
	12.25"	22	3.00	4.44	7.83	11.90	9.00	0.33	11.05
	8.50"	154	13.57	1.97	4.15	11.17	9.00	1.50	11.08
Drilling - Weight to Weight Time	17.50"	34	12.47	11.30	20.14	34.45	13.00	5.37	43.03
	12.25"	29	6.96	11.56	13.27	17.42	13.00	0.92	13.25
	8.50"	54	22.17	15.32	23.39	33.37	13.00	10.50	47.33
Casing - Slip to Slip Connection Time	17.50"	70	4.22	2.18	2.93	5.78	1.75	2.18	51.63
	12.25"	138	6.96	2.14	2.98	3.93	1.75	2.94	42.21
	8.50"	124	5.32	1.45	1.89	5.26	1.75	1.87	35.12

Total Savings Potential:	1.41 days	(31.26 % / 4.27 %)
Total KPI Duration:	4.50 days	
Total Duration:	32.93 days	

Figure 81: Saving potential Report